Introduction

2018 Q3 in Review

The results of the energy market were competitive in the first nine months of 2018. The goal of competition is to provide customers wholesale power at the lowest possible price, but no lower. The PJM markets work, even if not perfectly. The results of the base capacity auction for 2021/2022 were not competitive and the related issues need to be addressed. The PJM markets bring customers the benefits of competition. But the PJM markets, and wholesale power markets in the U.S., face new challenges that potentially threaten the viability of competitive markets.

The wholesale power grid is clearly resilient. The focus should be on ensuring that ongoing challenges to resilience are analyzed and addressed within a market framework. The real resilience question is whether the market construct itself is resilient. Can markets, and the market based regulatory construct, coexist with efforts to increase the role of renewable resources through nonmarket revenue?

The solution must recognize that states have authority over generation and can choose to reregulate at any time. Although most PJM states have ceded authority over generation to wholesale power markets regulated by the Commission and many have created competitive retail markets that depend on competitive wholesale power markets, the states can reverse that decision. Nonetheless, state policies evince a distinction between the approach to traditional generation assets and renewable energy assets. States, for environmental policy reasons not directly related to competitive wholesale power markets, have created significant nonmarket payments for renewable energy under the general heading of renewable portfolio standards, RPS. States have pursued these policies, not to undercut competitive wholesale power markets, but to reduce carbon and other emissions. The impacts of these policies on markets are real and growing but are not the intended result of renewable energy policies.

The solution must also recognize the role of competitive markets and that competitive markets need internally consistent rules in order to provide the incentives necessary for the markets to work.

It is essential that any approach to the PJM markets incorporate a consistent view of how the preferred market design is expected to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives to competitive market participants to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market. The MMU calls this approach the Sustainable Market Rule (SMR).

A sustainable competitive wholesale power market must recognize three salient structural elements: state nonmarket revenues for renewable energy; a significant level of generation resources subject to cost of service regulation; and the structure and performance of the existing market based generation fleet. The relatively recent provision of nonmarket revenues to specific uneconomic existing resources, primarily nuclear power plants, is also a fact, but this is limited to a few units and is not widespread at present. The potential for additional nonmarket revenues for existing uneconomic coal and nuclear plants is also real, based on statements from the U.S. Department of Energy. Subsidies to specific resources that are uneconomic as a result of competition are an effort to reverse market outcomes with no commitment to a regulatory model and no attempt to mitigate negative impacts on competition. The unit specific subsidy model is inconsistent with the PJM market design and inconsistent with the market paradigm and constitutes a significant threat to both.

The existing FRR approach remains an option for utilities with regulated revenues based on cost of service rates, including both privately and publicly owned (including public power entities and electric cooperatives) utilities. Such regulated utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity.

Given that states have increasingly aggressive renewable energy targets, a core goal of a competitive market design should be to ensure that the resources required to provide reliability receive appropriate competitive market incentives for entry and for ongoing investment and for exit when uneconomic. A significant level of renewable resources, operating with zero or near zero marginal costs, will result in very low energy prices. Since renewable resources are intermittent, the contribution of renewables to meeting reliability targets must be analyzed carefully to ensure that the capacity value is calculated correctly.

In order to attract and retain adequate resources for the reliable operation of the energy market, revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy market that are directly affected by nonmarket sources.

Price suppression below the competitive level in the capacity market should not be acceptable and is not consistent with a competitive market design. Harmonizing means that the integrity of each paradigm is maintained and respected. Harmonizing permits nonmarket resources to have an unlimited impact on energy markets and energy prices. Harmonizing means designing a capacity market to account for these energy market impacts, clearly limiting the impact of nonmarket revenues on the capacity market and ensuring competitive outcomes in the capacity market and thus in the entire market.

The expected impact of the SMR design on the offers and clearing of renewable resources and nuclear plants would be from zero to insignificant. The competitive offers of renewables, based on the net ACR of current technologies, are likely to clear in the capacity market. The competitive offers of nuclear plants, based on net ACR, are likely to clear in the capacity market.

Cost of service resources have the option of using the existing FRR rules, which would allow regulated utilities to opt out of the capacity market. The expected impact of the SMR design on the offers and clearing of regulated cost of service resources that remained in the capacity market would be from zero to insignificant. The competitive offers of these resources, based on net ACR, are likely to clear in the capacity market.

To the extent that there are shared broader goals related to PJM markets, they should also be addressed. If society determines that carbon is a pollutant with a negative value, a market approach to carbon is preferred to a technology or unit specific subsidy approach. Unit specific subsidies are not an efficient approach. Implementation of a carbon price is a market approach which would let market participants respond in efficient and innovative ways to the price signal rather than relying on planners to identify specific technologies or resources to be subsidized. For example, individual state REC policies with a range of implied carbon prices from $5 per tonne to $900 per tonne is not an effective or efficient approach to carbon pricing. It would be helpful to determining whether an agreement among PJM states could be reached on carbon pricing if PJM would offer to model the impact of various levels of carbon prices on the dispatch and economic viability of units in PJM and the associated flow of dollars to states in the form of carbon revenue. With this information, PJM should offer to meet with the states in an effort to find out whether there is a form of carbon pricing and revenue distribution that all the states could agree to.

An evaluation of the economics of the PJM nuclear fleet (18 plants) based on public data shows that some nuclear plants are at risk of retirement. The exact number depends on the evaluation criteria. Using historical data, nine plants with a total capacity of 14,027 MW did not recover their avoidable costs in two of the last three years. Based on forward prices for energy and the known forward prices for capacity, all but three nuclear plants would cover their annual avoidable costs on average over the next four years (2018 through 2021). The three plants are Davis Besse, Perry, and Three Mile Island (TMI). In May 2017, TMI requested deactivation in 2019. In March 2018, Davis Besse and Perry requested deactivation in 2021. All three plants are single unit sites which have higher operating costs per MWh than multiple unit plants. The three plants together are 2,939 MW and all have requested deactivation. Net revenues for nuclear power plants increased significantly in 2018 to date.

There are some nuclear power plants in PJM that are not economic at expected levels of energy and capacity market clearing prices. There are some coal plants that are not economic at recent levels of energy and capacity market clearing prices. The decisions on how to proceed belong to the owners of those plants. The fact that some plants are uneconomic does not call into question the fundamentals of PJM markets. Many generating plants have retired in PJM since the introduction of markets and many generating plants have been built since the introduction of markets.

The level of potential retirements does not imply a reliability issue in PJM and does not imply a fuel security issue in PJM. A comparison of the total units at risk and the current excess capacity in PJM suggests that, ignoring local reliability issues, the current and expected excess capacity is of the same order of magnitude as the units at risk. PJM had excess reserves of more than 9,000 MW on June 1, 2018, and will have excess reserves of almost 16,000 MW on June 1, 2019, based on current positions. There are currently 101,393 MW in the PJM generator interconnection queues, including suspended units. Of that, 29,452 MW have a Construction Services Agreement (CSA), the last agreement required in the interconnection process. For generators with a CSA, 74.4 percent of MW has gone into service. Based on that history, 21,912 MW of new generation with a CSA are expected to go into service.

The PJM markets have worked to provide incentives to entry and to retaining capacity. Capacity investments in PJM were generally financed by market sources. Of the 30,881.7 MW of additional capacity that cleared in Reliability Pricing Model (RPM) auctions for the 2007/2008 through 2017/2018 delivery years, 22,420 MW (72.6 percent) were based on market funding. Of the 13,553.8 MW of additional capacity that cleared in RPM auctions for the 2018/2019 through 2021/2022 delivery years, 11,752.4 MW (86.7 percent) were based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

Much of the reason that overall market outcomes are subject to legitimate criticism is that the capacity market has not been permitted to reveal the underlying supply and demand fundamentals in prices. Before market outcomes are rejected in favor of nonmarket choices, the capacity market should be permitted to work. It is more critical than ever to get capacity market prices correct. A number of capacity market design elements resulted in a substantial suppression of capacity market prices for multiple years and prices were increased above the competitive level in the 2021/2022 base auction.

These market design choices have and have had substantial impacts. Capacity prices that were suppressed substantially below the level consistent with supply and demand fundamentals affected some participants' long term decisions and led some market participants to seek subsidies. PJM has addressed the fundamental issues of the capacity market design in its Capacity Performance design, including price formation, product definition and performance incentives. But there are significant ongoing efforts to undo some of the key elements of the Capacity Performance design including performance incentives and product definition.

Energy prices in PJM are not too low. There is no evidence to support the need for a significant change to the calculation of LMP. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. PJM's fast start pricing and convex hull solutions would undercut LMP logic rather than directly addressing the underlying problem of scarcity pricing, including the impact of operator actions on the definition of scarcity. Current energy and reserve prices do not reflect market conditions when the market is tight. Rather than undercutting the basic LMP logic that is core to market efficiency, it would make more sense to directly incorporate the operators' demand for extramarginal MW in the reserve demand curves and to correct the design of reserve markets. But reform to scarcity pricing and reserve markets should not become a mechanism to create supplemental revenue sources to support uneconomic units. Targeted increases to the demand for reserves when the market is tight would address price formation in the energy market.

Competitive markets were introduced as an alternative form of regulation to ensure that wholesale power is provided at the lowest possible price. The PJM market design does not incorporate a laissez faire approach. The PJM market remains regulated. The PJM market design incorporates a variety of rules designed to help ensure competitive outcomes. When basic elements of those rules are modified, e.g. the raising of the overall $1,000 per MWh offer cap and the introduction of hourly offers in place of daily offers, it is essential that effective market power mitigation be maintained.

The price of energy must reflect supply and demand fundamentals. The inclusion of gas costs and other fuel costs in energy market offers must be based on market prices. The fuel cost policy for every unit documents the process by which a unit owner calculates the fuel cost component of its cost-based offers. Fuel cost policies must be algorithmic, verifiable and systematic to ensure that only market-based short run marginal costs are included in fuel costs, especially when markets are stressed. FERC's order on hourly offers means that generators have the ability to appropriately reflect gas cost changes in energy offers during the operating day in order to permit the energy market to reflect the current cost of gas. But offer changes should be based only on algorithmic and verifiable changes in gas cost and therefore not permit the exercise of market power.

The application of market power mitigation rules in the Day-Ahead Energy Market and the Real-Time Energy Market helps ensure competitive market outcomes even in the presence of structural market power. But the efficacy of market power mitigation rules depends on the definition of a competitive offer. A competitive offer is equal to short run marginal costs. The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, as currently interpreted by PJM, is not correct. Some unit owners include costs that are not short run marginal costs in offers, including long term maintenance costs. This issue can be resolved by simple changes to the PJM Market Rules to incorporate a clear and accurate definition of short run marginal costs. PJM Manual 15 should be replaced with a straightforward description of the components of cost offers based on short run marginal costs and the correct calculation of cost offers.

The overall energy market results in the first nine months of 2018 support the conclusion that energy prices in PJM are set, generally, by marginal units offering at, or close to, their short run marginal costs, although this is not always the case. This is evidence of generally competitive behavior, although the behavior of some participants raises concerns about economic withholding. The performance of the PJM markets under high load conditions and rapidly changing load conditions has raised a number of concerns related to aggregate market power, or the ability to increase markups substantially in tight market conditions, related to the uncertainties about the pricing and availability of natural gas, and related to the role of demand response and interchange transactions.

One of the benefits of competitive power markets is that changes in input prices and changes in the balance of supply and demand are reflected immediately in energy prices. PJM real-time energy market prices increased significantly in the first nine months of 2018 compared to the first nine months of 2017. The load-weighted, average real-time LMP was 29.9 percent higher in the first nine months of 2018 than in the first nine months of 2017, $39.43 per MWh versus $30.36 per MWh.

The markup conduct of individual owners and units has an identifiable impact on market prices. In the Real-Time Energy Market, the unadjusted markup component of LMP increased from 15.9 percent of the real-time load-weighted average LMP in the first nine months of 2017 to 20.0 percent in the first nine months of 2018. Participant behavior was evaluated as competitive because marginal units generally made offers at, or close to, their short run marginal costs. But the increased markup results are a reminder that aggregate market power remains an issue when market conditions are tight, that there are issues with the implementation of the three pivotal supplier test, and that cost-based offers need to reflect short run marginal costs. There are generation owners who routinely include high markups in price-based offers on some units.

Net revenue is a key measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenues are significantly affected by fuel prices, energy prices and capacity prices. Energy prices and fuel prices were both higher and more volatile in the first nine months of 2018 than in the first nine months of 2017. All unit types ran with higher energy market margins as a result. In the first nine months of 2018, average energy market net revenues increased by 70 percent for a new combustion turbine (CT), 39 percent for a new combined cycle (CC), 202 percent for a new coal plant (CP), 37 percent for a new nuclear plant (NP), 461 percent for a new diesel (DS), 22 percent for a new wind installation, and 10 percent for a new solar installation compared to the first nine months of 2017.

Load pays for the transmission system and contributes congestion revenues. For that reason, FTRs and later ARRs were intended to return congestion revenues to load. The annual ARR allocation should be designed to ensure that load receives the rights to all congestion revenues, without requiring contract path physical transmission rights that are impossible to define correctly and enforce in nodal, network LMP markets. The current ARR/FTR design does not serve as an efficient or effective way to ensure that load receives all the congestion revenues or that load receives the auction revenues associated with all the potential congestion revenues.

The goal of the design should be to assign the rights to 100 percent of the congestion revenues to load. But the actual results fall well short of that goal. The current allocation of congestion revenue resulted in a total of $2,209.1 million in unreturned congestion revenue to ARR holders, and only a 71.2 percent congestion offset over the last eight planning periods.

The FTR/ARR design should be significantly modified in order to return the design to its original purpose and function, which was to return congestion revenues to load.

The approach to transmission investment should emphasize the role of competition in ensuring required transmission expansion of all types at the lowest possible cost.

The PJM markets and PJM market participants from all sectors face significant challenges. PJM and its market participants will need to continue to work constructively to address these challenges to ensure the continued effectiveness of PJM markets.

PJM Market Summary Statistics

Table 1-1 shows selected summary statistics describing PJM markets.

Table 1-1 PJM Market Summary Statistics: January through September, 2017 and 2018[1]

	Jan - Sep, 2017	Jan - Sep, 2018	Percent Change
Average Hourly Load (MW)	87,243	92,047	5.5%
Average Hourly Generation (MW)	91,658	95,561	4.3%
Peak Load (MW)	142,387	147,042	3.3%
Installed Capacity at September 30 (MW)	182,459	184,560	1.2%
Load Weighted Average Real Time LMP ($/MWh)	$30.36	$39.43	29.9%
Total Congestion Costs ($ Million)	$455.40	$1,116.20	145.1%
Total Uplift Charges ($ Million)	$84.65	$177.22	109.4%
Total PJM Billing ($ Billion)	$29.51	$37.95	28.6%

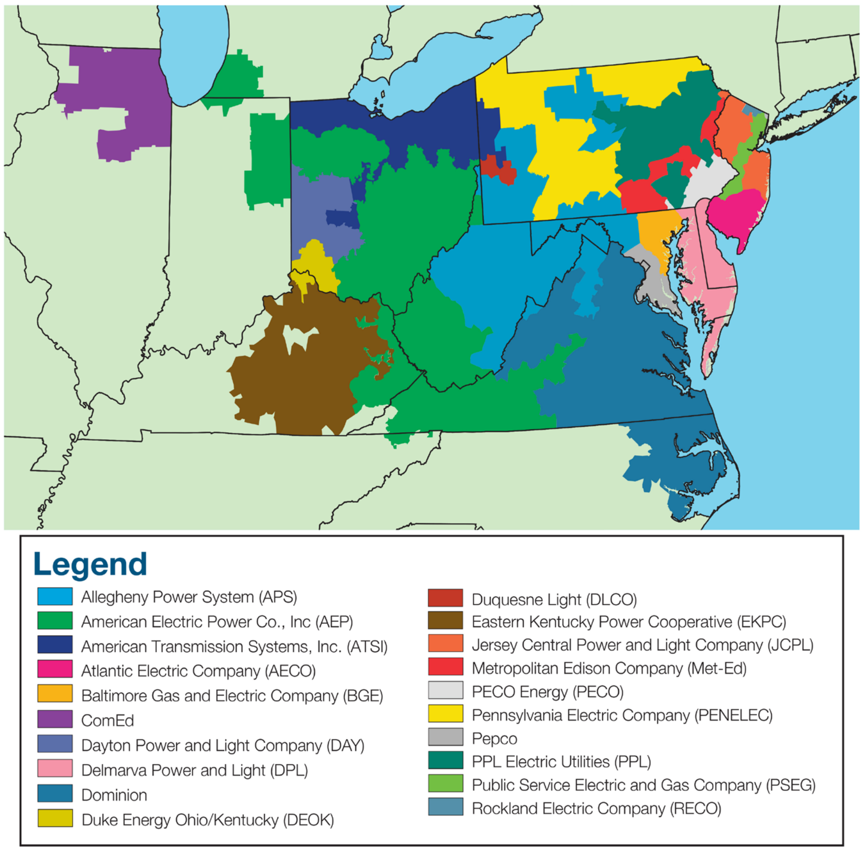
PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of September 30, 2018, had installed generating capacity of 184,560 megawatts (MW) and 1,053 members including market buyers, sellers and traders of electricity in a region including more than 65 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia (Figure 1-1).[2] [3] [4]

1 The load reported in this table is the accounting load plus net withdrawals at generator buses. The average hourly accounting load is reported in Section 3, "Energy Market."
2 See PJM. "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
3 See PJM. "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.
4 See the *2017 State of the Market Report for PJM*, Volume II, Appendix A:"PJM Geography" for maps showing the PJM footprint and its evolution prior to 2018.

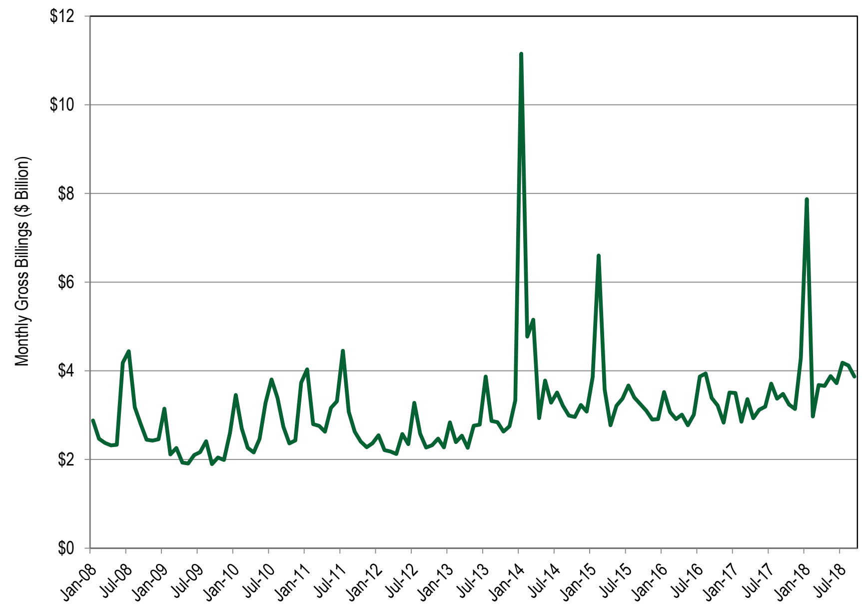
As part of the market operator function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

Figure 1-1 PJM's footprint and its 20 control zones



In the first nine months of 2018, PJM had total billings of \$37.95 billion, an increase of 28.6 percent from \$29.51 billion in the first nine months of 2017 (Figure 1-2).[5]

Figure 1-2 PJM reported monthly billings (\$ Billion): 2008 through September 2018



PJM operates the Day-Ahead Energy Market, the Real-Time Energy Market, the Reliability Pricing Model (RPM) Capacity Market, the Regulation Market, the Synchronized Reserve Market, the Day-Ahead Scheduling Reserve (DASR) Market and the Financial Transmission Rights (FTRs) Markets.

PJM introduced energy pricing with cost-based offers and market-clearing nodal prices on April 1, 1998, and market-clearing nodal prices with market-based offers on April 1, 1999. PJM introduced the Daily Capacity Market on January 1, 1999, and the Monthly and Multimonthly Capacity Markets for the

5 Monthly and year to date billing values are provided by PJM.

January through May 1999 period. PJM implemented FTRs on May 1, 1999. PJM implemented the Day-Ahead Energy Market and the Regulation Market on June 1, 2000. PJM modified the Regulation Market design and added a market in Synchronized Reserve on December 1, 2002. PJM introduced an Auction Revenue Rights (ARR) allocation process and an associated Annual FTR Auction effective June 1, 2003. PJM introduced the RPM Capacity Market effective June 1, 2007. PJM implemented the DASR Market on June 1, 2008. PJM introduced the Capacity Performance capacity market design effective on August 10, 2015, with the Base Residual Auction for 2018/2019.[6 7]

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first nine months of 2018, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the Independent Market Monitor for PJM, also referred to as the Market Monitoring Unit or MMU.

For each PJM market, the market structure is evaluated as competitive or not competitive, and participant behavior is evaluated as competitive or not competitive. Most important, the outcome of each market, market performance, is evaluated as competitive or not competitive.

The MMU also evaluates the market design for each market. The market design serves as the vehicle for translating participant behavior within the market structure into market performance. This report evaluates the effectiveness of the market design of each PJM market in providing market performance consistent with competitive results.

Market structure refers to the cost, demand, and ownership structure of the market. The three pivotal supplier (TPS) test is the most relevant measure of market structure because it accounts for the ownership of assets and the relationship among the pattern of ownership, the resource costs, and the market demand using actual market conditions with both temporal and geographic granularity. Market shares and the related Herfindahl-Hirschman Index (HHI) are also measures of market structure.

Participant behavior refers to the actions of individual market participants, also sometimes referred to as participant conduct.

Market performance refers to the outcomes of the market. Market performance results from the behavior of market participants within a market structure, mediated by market design.

Market design means the rules under which the entire relevant market operates, including the software that implements the market rules. Market rules include the definition of the product, the definition of short run marginal cost, rules governing offer behavior, market power mitigation rules, and the definition of demand. Market design is characterized as effective, mixed or flawed. An effective market design provides incentives for competitive behavior and permits competitive outcomes. A mixed market design has significant issues that constrain the potential for competitive behavior to result in competitive market outcomes, and does not have adequate rules to mitigate market power or incent competitive behavior. A flawed market design produces inefficient outcomes which cannot be corrected by competitive behavior.

The MMU concludes for the first nine months of 2018:

6 See also the *2017 State of the Market Report for PJM*, Volume 2, Appendix B: "PJM Market Milestones."

7 Analysis of 2018 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. In June 2011, the American Transmission Systems, Inc. (ATSI) Control Zone joined PJM. In January 2012, the Duke Energy Ohio/Kentucky Control Zone joined PJM. In June 2013, the Eastern Kentucky Power Cooperative (EKPC) joined PJM. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory prior to 2017, see *2017 State of the Market Report for PJM*, Volume 2, Appendix A: "PJM Geography."

Energy Market Conclusion

Table 1-2 The Energy Market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Partially Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

- The aggregate market structure was evaluated as partially competitive because the aggregate market power test based on pivotal suppliers indicates that the aggregate day-ahead and real-time market structure was not competitive on every day. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM energy market in the first nine months of 2018 was unconcentrated by FERC HHI standards in 92.4 percent of market hours and moderately concentrated in 7.6 percent of market hours. Average HHI was 847 with a minimum of 624 and a maximum of 1242 in the first nine months of 2018. The PJM energy market peaking segment of supply was highly concentrated. The fact that the average HHI is in the unconcentrated range and the maximum hourly HHI is in the moderately concentrated range does not mean that the aggregate market was competitive in all hours. As demonstrated for the day-ahead market and the real-time market, it is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints and local reliability issues. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test identified local market power and resulted in offer capping to force competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed because unit owners can exercise market power even when mitigated.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets, although the behavior of some participants both routinely and during periods of high demand represents economic withholding and the markups of those participants affected LMP.
- Market performance was evaluated as competitive because market results in the energy market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets, although high markups during periods of high demand did affect prices.
- Market design was evaluated as effective because the analysis shows that the PJM energy market resulted in competitive market outcomes. In general, PJM's energy market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design identifies market power and causes the market to provide competitive market outcomes in most cases although issues with the implementation of market power mitigation and development of cost-based offers remain. The role of UTCs in the Day-Ahead Energy Market continues to cause concerns.
- PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[8] The approach to market power mitigation in PJM has focused on market designs that promote

8 OATT Attachment M (PJM Market Monitoring Plan).

competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM energy market, this occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[9] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power even when market power mitigation rules are applied. These issues need to be addressed. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of variable operating and maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Now that generators are allowed to modify offers hourly, market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the new rules permitting cost-based offers in excess of $1,000 per MWh.

9 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.

Capacity Market Conclusion

Table 1-3 The Capacity Market results were not competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Not Competitive	
Market Performance	**Not Competitive**	**Mixed**

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[10]
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[11]
- Participant behavior was evaluated as not competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. But the net CONE times B offer cap under the capacity performance design, in the absence of performance assessment hours, exceeds the competitive level and should be reevaluated for each BRA. In the 2021/2022 RPM Base Residual Auction, some participants' offers were above the competitive level. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the non-performance charge rate is defined as Net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the

10 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test. In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the test.

11 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test.

way in which most market participants offered in this and prior capacity performance auctions.

- Market performance was evaluated as not competitive. Although structural market power exists in the Capacity Market, a competitive outcome can result from the application of market power mitigation rules. The outcome of the 2021/2022 RPM Base Residual Auction was not competitive as a result of participant behavior which was not competitive, specifically offers which exceeded the competitive level.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design and the capacity performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters, the inclusion of imports which are not substitutes for internal capacity resources, and the definition of the default offer cap.

Tier 2 Synchronized Reserve Market Conclusion

Table 1-4 The tier 2 synchronized reserve market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Mixed**

- The tier 2 synchronized reserve market structure was evaluated as not competitive because of high levels of supplier concentration.
- Participant behavior was evaluated as competitive because the market rules require competitive, cost-based offers.
- Market performance was evaluated as competitive because the interaction of participant behavior with the market design results in competitive prices.
- Market design was evaluated as mixed. Market power mitigation rules result in competitive outcomes despite high levels of supplier concentration. However, tier 1 reserves are inappropriately compensated when the nonsynchronized reserve market clears with a nonzero price.

Day-Ahead Scheduling Reserve Market Conclusion

Table 1-5 The day-ahead scheduling reserve market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Mixed	
Market Performance	**Competitive**	**Mixed**

- The day-ahead scheduling reserve market structure was evaluated as not competitive because market participants failed the three pivotal supplier test in 13.4 percent of all cleared hours in the first nine months of 2018.
- Participant behavior was evaluated as mixed because while most offers were equal to marginal costs, a significant proportion of offers reflected economic withholding.
- Market performance was evaluated as competitive because there were adequate offers in every hour to satisfy the requirement and the clearing prices reflected those offers, although there is concern about offers above the competitive level affecting prices. Offers above $0.00 were part of the clearing price in 96.6 percent of cleared hours.
- Market design was evaluated as mixed because the DASR product does not include performance obligations. Offers should be based on opportunity cost only, to ensure competitive outcomes and that market power cannot be exercised.

Regulation Market Conclusion

Table 1-6 The regulation market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Flawed

- The regulation market structure was evaluated as not competitive because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 82.8 percent of the hours in the first nine months of 2018.
- Participant behavior in the PJM Regulation Market was evaluated as competitive for the first nine months of 2018 because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in noncompetitive behavior.
- Market performance was evaluated as competitive, despite significant issues with the market design.
- Market design was evaluated as flawed. The market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. The market results continue to include the incorrect definition of opportunity cost. The result is significantly flawed market signals to existing and prospective suppliers of regulation.

FTR Auction Market Conclusion

Table 1-7 The FTR auction markets results were competitive

Market Element	Evaluation	Market Design
Market Structure	Partially Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Flawed

- Market structure was evaluated as partially competitive because while purchasing FTRs in the FTR Auction is voluntary, issues have been identified with the assignment of system capability between ARRs and FTRs as well as the accuracy of modeling in the Long Term FTR Auctions. In addition, the ownership structure of Long Term FTRs, particularly the three year product, is highly concentrated.
- Participant behavior was evaluated as competitive because there was no evidence of anticompetitive behavior.
- Market performance was evaluated as competitive because it reflected the interaction between participant demand behavior and the expected system capability that PJM made available for sale as FTRs. It is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable.
- Market design was evaluated as flawed because there are significant flaws with the basic ARR/FTR design. The market design is not an efficient or effective way to ensure that all congestion revenues are returned to load. ARR holders' rights to congestion revenues are not defined clearly enough. ARR holders cannot determine the price at which they are willing to sell rights to congestion revenue. Issues have been identified with the share of system capability made available for sale as FTRs by PJM.

Role of MMU

The FERC assigns three core functions to MMUs: reporting, monitoring and market design.[12] These functions are interrelated and overlap. The PJM Market Monitoring Plan establishes these functions, providing that the MMU is responsible for monitoring: compliance with the PJM Market Rules; actual or potential design flaws in the PJM Market Rules; structural problems in the PJM Markets that may inhibit a robust and competitive market; the actual or potential exercise of market power or violation of the market rules by a Market Participant; PJM's implementation of the PJM Market Rules or operation of the PJM Markets; and such matters as are necessary to prepare reports.[13]

Reporting

The MMU performs its reporting function primarily by issuing and filing annual and quarterly state of the market reports; regular reports on market issues; such as RPM auction reports; reports responding to requests from regulators and other authorities; and ad hoc reports on specific topics. The state of the market reports provide a comprehensive analysis of market structure, participant conduct and market performance for the PJM markets. State of the market reports and other reports are intended to inform PJM, the PJM Board, FERC, other regulators, other authorities, market participants, stakeholders and the general public about how well PJM markets achieve the competitive outcomes necessary to realize the goals of regulation through competition, and how the markets can be improved.

The MMU presents reports directly to PJM stakeholders, PJM staff, FERC staff, state commission staff, state commissions, other regulatory agencies and the general public. Report presentations provide an opportunity for interested parties to ask questions, discuss issues, and provide feedback to the MMU.

12 18 CFR § 35.28(g)(3)(ii); see also *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶31,281 (2008) ("Order No. 719"), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶31,292 (2009), *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

13 OATT Attachment M § IV; 18 CFR § 1c.2.

Monitoring

To perform its monitoring function, the MMU screens and monitors the conduct of Market Participants under the MMU's broad purview to monitor, investigate, evaluate and report on the PJM Markets.[14] The MMU has direct, confidential access to the FERC.[15] The MMU may also refer matters to the attention of state commissions.[16]

The MMU monitors market behavior for violations of FERC Market Rules and PJM Market Rules, including the actual or potential exercise of market power.[17] The MMU will investigate and refer "Market Violations," which refer to any of "a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies…"[18] [19] [20] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[21]

An important component of the monitoring function is the review of inputs to mitigation. The actual or potential exercise of market power is addressed in part through *ex ante* mitigation rules incorporated in PJM's market clearing software for the energy market, the capacity market and the regulation market. If a market participant fails the TPS test in any of these markets its offer is set

14 OATT Attachment M § IV.

15 OATT Attachment M § IV.K.3.

16 OATT Attachment M § IV.H.

17 OATT § I.1 ("FERC Market Rules" mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish… "PJM Market Rules" mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.")

18 The FERC defines manipulation as engaging "in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity." 18 CFR § 1c.2(a)(3). Manipulation may involve behavior that is consistent with the letter of the rules, but violates their spirit. An example is market behavior that is economically meaningless, such as equal and opposite transactions, which may entitle the transacting party to a benefit associated with volume. Unlike market power or rule violations, manipulation must be intentional. The MMU must build its case, including an inference of intent, on the basis of market data.

19 OATT § I.1.

20 The MMU has no prosecutorial or enforcement authority. The MMU notifies the FERC when it identifies a significant market problem or market violation. OATT Attachment M § IV.I.1. If the problem or violation involves a market participant, the MMU discusses the matter with the participant(s) involved and analyzes relevant market data. If that investigation produces sufficient credible evidence of a violation, the MMU prepares a formal referral and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff. *Id.* If the problem involves an existing or proposed law, rule or practice that exposes PJM markets to the risk that market power or market manipulation could compromise the integrity of the markets, the MMU explains the issue, as appropriate, to the FERC, state regulators, stakeholders or other authorities. The MMU may also participate as a party or provide information or testimony in regulatory or other proceedings.

21 OATT Attachment M § IV.C.

to the lower of its price-based or cost-based offer. This prevents the exercise of market power and ensures competitive pricing, provided that the cost-based offer accurately reflects short run marginal cost.

If the cost-based offer does not accurately reflect short run marginal cost, the market power mitigation process does not ensure competitive pricing in PJM markets. The MMU evaluates the fuel cost policy for every unit as well as the other inputs to cost-based offers. PJM Manual 15 does not clearly or accurately describe the short run marginal cost of generation. Manual 15 should be replaced with a straightforward description of the components of cost offers based on short run marginal costs and the correct calculation of cost offers. The MMU evaluates every offer in each capacity market (RPM) auction using data submitted to the MMU through web-based data input systems developed by the MMU.[22]

The MMU also reviews operational parameter limits included with unit offers, evaluates compliance with the requirement to offer into the energy and capacity markets, evaluates the economic basis for unit retirement requests and evaluates and compares offers in the Day-Ahead and Real-Time Energy Markets.[23] [24] [25] [26]

The MMU reviews offers and inputs in order to evaluate whether those offers raise market power concerns. Market participants, not the MMU, determine and take responsibility for offers that they submit and the market conduct that those offers represent. If the MMU has a concern about an offer, the MMU may raise that concern with the FERC or other regulatory authorities. The FERC and other regulators have enforcement and regulatory authority that they may exercise with respect to offers submitted by market participants. PJM also reviews offers, but it does so in order to determine whether offers comply with the PJM tariff and manuals. PJM, in its role as the market operator, may reject an offer that fails to comply with the market rules. The respective reviews performed by the MMU and PJM are separate and non-sequential.

22 OATT Attachment M–Appendix § II.E.
23 OATT Attachment M–Appendix § II.B.
24 OATT Attachment M–Appendix § II.C.
25 OATT Attachment M–Appendix § IV.
26 OATT Attachment M–Appendix § VII.

The PJM Markets monitored by the MMU include market related procurement processes conducted by PJM, such as for Black Start resources included in the PJM system restoration plan.[27] [28]

The MMU also monitors transmission planning, interconnections and rules for vertical market power issues, and with the introduction of competitive transmission development policy in Order No. 1000, horizontal market power issues.[29]

Market Design

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[30] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[31] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM Management, and the PJM Board; participates in PJM stakeholder meetings or working groups regarding market design matters; publishes proposals, reports or studies on such market design issues; and makes filings with the Commission on market design issues.[32] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[33] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[34]

New Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes,"[35] the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for

27 OATT Attachment M–Appendix § II(p).
28 OATT Attachment M–Appendix § III.
29 OA Schedule 6 § 1.5.
30 OATT Attachment M § IV.D.
31 *Id.*
32 *Id.*
33 *Id.*
34 OATT Attachment M § VI.A.
35 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

competitive results in PJM markets and for continued improvements in the functioning of PJM markets.

In this *2018 Quarterly State of the Market Report for PJM: January through September*, the MMU includes nine new or modified recommendations.[36]

New Recommendations from Section 3, Energy Market

- The MMU recommends that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs) in the capacity market default offer cap, and only include those events that trigger emergencies for at least a defined sub-zonal or zonal level. (Priority: Medium. New Recommendation. Status: Not adopted.)
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. New Recommendation. Status: Not adopted.)

New Recommendation from Section 5, Capacity Market

- The MMU recommends that capacity market sellers be required to request the use of minimum MW quantities greater than 0 MW (inflexible sell offer segments) and that the requests should only be permitted for defined physical reasons. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendations from Section 10, Ancillary Service Markets

- The MMU recommends that the $7.50 margin be eliminated from the definition of the cost of tier 2 synchronized reserve because it is a markup and not a cost. (Priority: Medium. New Recommendation. Status: Not adopted.)
- The MMU recommends that, for calculating the penalty for a tier 2 resource failing to meet its scheduled obligation during a spinning event, the definition of the IPI be changed from the average number of days between events to the actual number of days since the last event greater than 10 minutes. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that offers in the DASR Market be based on opportunity cost only in order to eliminate market power. (Priority: Low. First reported 2009. Modified 2018. Status: Not adopted.)
- The MMU recommends that payments for reactive capability, if continued, be based on the 0.90 power factor that PJM has determined is necessary. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendation from Section 12, Generation and Transmission Planning

- The MMU recommends that PJM reevaluate the rules governing cost benefit analysis and cost allocation for economic projects. (Priority: Medium. New recommendation. Status: Not adopted.)

Total Price of Wholesale Power

The total price of wholesale power is the total price per MWh of purchasing wholesale electricity from PJM markets. The total price is an average price and actual prices vary by location. The total price includes the price of energy, capacity, ancillary services, and transmission service, administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1-8 shows the average price, by component, for the first nine months of 2017 and 2018.

36 New recommendations include all MMU recommendations that were reported for the first time in the *2018 Quarterly State of the Market Report for PJM: January through September.*

Each of the components is defined in PJM's Open Access Transmission Tariff (OATT) and PJM Operating Agreement and each is collected through PJM's billing system.

Components of Total Price

- The Energy component is the real time load weighted average PJM locational marginal price (LMP).
- The Capacity component is the average price per MWh of Reliability Pricing Model (RPM) payments.
- The Transmission Service Charges component is the average price per MWh of network integration charges, and firm and nonfirm point to point transmission service.[37]
- The Energy Uplift (Operating Reserves) component is the average price per MWh of day-ahead and balancing operating reserves and synchronous condensing charges.[38]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[39]
- The Regulation component is the average cost per MWh of regulation procured through the PJM Regulation Market.[40]
- The PJM Administrative Fees component is the average cost per MWh of PJM's monthly expenses for a number of administrative services, including Advanced Control Center (AC^2) and OATT Schedule 9 funding of FERC, OPSI, CAPS and the MMU.
- The Transmission Enhancement Cost Recovery component is the average cost per MWh of PJM billed (and not otherwise collected through utility rates) costs for transmission upgrades and projects, including annual recovery for the TrAIL and PATH projects.[41]

37 OATT §§ 13.7, 14.5, 27A & 34.
38 OA Schedules 1 §§ 3.2.3 & 3.3.3.
39 OATT Schedule 2 and OA Schedule 1 § 3.2.3B. The line item in Table 1-8 includes all reactive services charges.
40 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
41 OATT Schedule 12.

- The Capacity (FRR) component is the average cost per MWh under the Fixed Resource Requirement (FRR) Alternative for an eligible LSE to satisfy its Unforced Capacity obligation.[42]
- The Emergency Load Response component is the average cost per MWh of the PJM Emergency Load Response Program.[43]
- The Day-Ahead Scheduling Reserve component is the average cost per MWh of Day-Ahead scheduling reserves procured through the Day-Ahead Scheduling Reserve Market.[44]
- The Transmission Owner (Schedule 1A) component is the average cost per MWh of transmission owner scheduling, system control and dispatch services charged to transmission customers.[45]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[46]
- The Black Start component is the average cost per MWh of black start service.[47]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[48]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[49]
- The Economic Load Response component is the average cost per MWh of day ahead and real time economic load response program charges to LSEs.[50]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[51]

42 RAA Schedule 8.1.
43 OATT PJM Emergency Load Response Program.
44 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
45 OATT Schedule 1A.
46 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
47 OATT Schedule 6A. The line item in Table 1-8 includes all Energy Uplift (Operating Reserves) charges for Black Start.
48 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
49 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
50 OA Schedule 1 § 3.6.
51 OA Schedule 1 § 5.3b.

- The nonsynchronized reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.[52]
- The Emergency Energy component is the average cost per MWh of emergency energy.[53]

Table 1-8 shows that Energy, Capacity and Transmission Charges are the three largest components of the total price per MWh of wholesale power, comprising 97.6 percent of the total price per MWh in the first nine months of 2018.

Table 1-8 Total price per MWh by category: January through September, 2017 and 2018[54 55]

Category	Jan-Sep 2017 $/MWh	Jan-Sep 2017 Percent of Total	Jan-Sep 2018 $/MWh	Jan-Sep 2018 Percent of Total	Percent Change
Load Weighted Energy	$30.36	58.2%	$39.43	63.8%	29.9%
Capacity	$10.94	21.0%	$12.43	20.1%	13.6%
Capacity	$10.91	20.9%	$12.40	20.1%	13.6%
Capacity (FRR)	$0.00	0.0%	$0.00	0.0%	0.0%
Capacity (RMR)	$0.03	0.1%	$0.04	0.1%	16.4%
Transmission	$9.41	18.1%	$8.43	13.6%	(10.5%)
Transmission Service Charges	$8.72	16.7%	$7.77	12.6%	(10.9%)
Transmission Enhancement Cost Recovery	$0.63	1.2%	$0.57	0.9%	(9.2%)
Transmission Owner (Schedule 1A)	$0.10	0.2%	$0.08	0.1%	(12.6%)
Transmission Seams Elimination Cost Assignment (SECA)	($0.04)	(0.1%)	$0.00	0.0%	(100.0%)
Transmission Facility Charges	$0.00	0.0%	$0.00	0.0%	0.0%
Ancillary	$0.77	1.5%	$0.76	1.2%	(1.0%)
Reactive	$0.42	0.8%	$0.38	0.6%	(9.6%)
Regulation	$0.13	0.2%	$0.18	0.3%	41.4%
Black Start	$0.09	0.2%	$0.07	0.1%	(20.6%)
Synchronized Reserves	$0.06	0.1%	$0.06	0.1%	(0.9%)
Non-Synchronized Reserves	$0.01	0.0%	$0.02	0.0%	129.8%
Day Ahead Scheduling Reserve (DASR)	$0.06	0.1%	$0.05	0.1%	(19.7%)
Administration	$0.53	1.0%	$0.46	0.7%	(13.9%)
PJM Administrative Fees	$0.50	1.0%	$0.43	0.7%	(14.3%)
NERC/RFC	$0.03	0.1%	$0.03	0.0%	(7.3%)
RTO Startup and Expansion	$0.00	0.0%	$0.00	0.0%	(16.1%)
Energy Uplift (Operating Reserves)	$0.12	0.2%	$0.26	0.4%	112.1%
Demand Response	$0.01	0.0%	$0.01	0.0%	(21.7%)
Load Response	$0.01	0.0%	$0.01	0.0%	(21.7%)
Emergency Load Response	$0.00	0.0%	$0.00	0.0%	0.0%
Emergency Energy	$0.00	0.0%	$0.00	0.0%	0.0%
Total Price ($/MWh)	$52.14	100.0%	$61.78	100.0%	18.5%
Total Load (GWh)	571,526		602,071		5.3%
Total Billing ($ Billions)	$29.80		$37.20		24.8%

52 OA Schedule 1 § 3.2.3A.001.
53 OA Schedule 1 § 3.2.6.
54 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.
55 The total billing in this table does not match the PJM reported total billing due to differences in calculation methodologies. For example, PJM accounts for all adjustments in the month billed, whereas the totals presented in these tables account for those adjustments in the month for which the adjustment was applied.

Table 1-9 shows the inflation adjusted average price, by component, for the first nine months of 2017 and 2018. To obtain the inflation adjusted average prices, the individual components' prices are deflated using the US Consumer Price Index for all items, Urban Consumers (with a base period of January 1998), as published by *Bureau of Labor Statistics*.[56]

Table 1-9 Inflation adjusted total price per MWh by category: January through September, 2017 and 2018[57]

Category	Jan-Sep 2017 $/MWh	Jan-Sep 2017 Percent of Total	Jan-Sep 2018 $/MWh	Jan-Sep 2018 Percent of Total	Percent Change
Load Weighted Energy	$20.05	58.2%	$25.45	63.9%	26.9%
Capacity	$7.23	21.0%	$8.01	20.1%	10.8%
Capacity	$7.21	20.9%	$7.98	20.0%	10.8%
Capacity (FRR)	$0.00	0.0%	$0.00	0.0%	0.0%
Capacity (RMR)	$0.02	0.1%	$0.02	0.1%	14.5%
Transmission	$6.22	18.1%	$5.43	13.6%	(12.6%)
Transmission Service Charges	$5.76	16.7%	$5.01	12.6%	(13.0%)
Transmission Enhancement Cost Recovery	$0.42	1.2%	$0.37	0.9%	(11.4%)
Transmission Owner (Schedule 1A)	$0.06	0.2%	$0.05	0.1%	(14.7%)
Transmission Seams Elimination Cost Assignment (SECA)	($0.02)	(0.1%)	$0.00	0.0%	(100.0%)
Transmission Facility Charges	$0.00	0.0%	$0.00	0.0%	0.0%
Ancillary	$0.51	1.5%	$0.49	1.2%	(3.1%)
Reactive	$0.28	0.8%	$0.25	0.6%	(11.8%)
Regulation	$0.09	0.2%	$0.12	0.3%	38.5%
Black Start	$0.06	0.2%	$0.05	0.1%	(22.4%)
Synchronized Reserves	$0.04	0.1%	$0.04	0.1%	(2.9%)
Non-Synchronized Reserves	$0.01	0.0%	$0.01	0.0%	127.3%
Day Ahead Scheduling Reserve (DASR)	$0.04	0.1%	$0.03	0.1%	(21.3%)
Administration	$0.35	1.0%	$0.29	0.7%	(15.9%)
PJM Administrative Fees	$0.33	1.0%	$0.28	0.7%	(16.3%)
NERC/RFC	$0.02	0.1%	$0.02	0.0%	(9.5%)
RTO Startup and Expansion	$0.00	0.0%	$0.00	0.0%	(15.0%)
Energy Uplift (Operating Reserves)	$0.08	0.2%	$0.17	0.4%	107.8%
Demand Response	$0.00	0.0%	$0.00	0.0%	(23.9%)
Load Response	$0.00	0.0%	$0.00	0.0%	(23.9%)
Emergency Load Response	$0.00	0.0%	$0.00	0.0%	0.0%
Emergency Energy	$0.00	0.0%	$0.00	0.0%	0.0%
Total Price ($/MWh)	$34.44	100.0%	$39.85	100.0%	15.7%
Total Load (GWh)	571,526		602,071		5.3%
Total Billing ($ Billions)	$19.68		$23.99		21.9%

56 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (October 11, 2018)
57 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Table 1-10 shows the average price, by component of the total wholesale power price per MWh, for calendar years 1999 through 2017.

Table 1-10 Total price per MWh by category: 1999 through 2017[58]

Category	1999 $/MWh	2000 $/MWh	2001 $/MWh	2002 $/MWh	2003 $/MWh	2004 $/MWh	2005 $/MWh	2006 $/MWh	2007 $/MWh	2008 $/MWh	2009 $/MWh	2010 $/MWh	2011 $/MWh	2012 $/MWh	2013 $/MWh	2014 $/MWh	2015 $/MWh	2016 $/MWh	2017 $/MWh
Load Weighted Energy	$34.07	$30.72	$36.65	$31.60	$41.23	$44.34	$63.46	$53.35	$61.66	$71.13	$39.05	$48.35	$45.94	$35.23	$38.66	$53.14	$36.16	$29.23	$30.99
Capacity	$0.14	$0.25	$0.27	$0.12	$0.08	$0.09	$0.04	$0.11	$3.58	$7.84	$10.79	$12.17	$10.37	$6.66	$7.29	$9.25	$11.25	$10.96	$11.27
Capacity	$0.14	$0.25	$0.27	$0.12	$0.08	$0.09	$0.03	$0.03	$3.53	$7.80	$10.78	$12.15	$9.71	$6.05	$7.13	$9.01	$11.12	$10.96	$11.23
Capacity (FRR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.53	$0.52	$0.11	$0.20	$0.13	$0.00	$0.00
Capacity (RMR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.08	$0.05	$0.04	$0.01	$0.02	$0.13	$0.08	$0.06	$0.04	($0.00)	($0.00)	$0.04
Transmission	$3.49	$4.13	$3.56	$3.46	$3.64	$3.43	$3.30	$3.34	$3.55	$3.83	$4.22	$4.33	$4.86	$5.32	$5.65	$6.46	$7.69	$8.42	$9.54
Transmission Service Charges	$3.41	$4.03	$3.48	$3.39	$3.57	$3.28	$2.71	$3.18	$3.45	$3.68	$4.03	$4.04	$4.49	$4.90	$5.21	$5.96	$7.09	$7.81	$8.83
Transmission Enhancement Cost Recovery	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.06	$0.11	$0.20	$0.27	$0.34	$0.36	$0.41	$0.51	$0.52	$0.64
Transmission Owner (Schedule 1A)	$0.07	$0.09	$0.08	$0.07	$0.07	$0.10	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.08	$0.08	$0.09	$0.09	$0.09	$0.10
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.05	$0.50	$0.07	$0.00	$0.00	$0.00	$0.00	($0.00)	$0.00	$0.00	$0.00	$0.00	$0.00	($0.03)
Transmission Facility Charges	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Ancillary	$0.41	$0.68	$0.75	$0.63	$0.91	$0.91	$1.19	$0.92	$1.00	$1.15	$0.78	$0.90	$0.90	$0.84	$1.24	$0.99	$0.91	$0.71	$0.77
Reactive	$0.26	$0.29	$0.22	$0.20	$0.24	$0.26	$0.26	$0.29	$0.29	$0.34	$0.36	$0.45	$0.41	$0.46	$0.76	$0.40	$0.37	$0.38	$0.43
Regulation	$0.15	$0.39	$0.53	$0.42	$0.50	$0.51	$0.80	$0.53	$0.63	$0.70	$0.34	$0.36	$0.32	$0.26	$0.25	$0.33	$0.23	$0.11	$0.14
Black Start	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.04	$0.14	$0.08	$0.08	$0.09	$0.09
Synchronized Reserves	$0.00	$0.00	$0.00	$0.01	$0.15	$0.13	$0.11	$0.08	$0.06	$0.08	$0.05	$0.07	$0.09	$0.04	$0.04	$0.12	$0.11	$0.05	$0.06
Non-Synchronized Reserves	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02	$0.01	$0.01
Day Ahead Scheduling Reserve (DASR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.01	$0.05	$0.05	$0.06	$0.05	$0.10	$0.07	$0.05
Administration	$0.23	$0.26	$0.73	$0.86	$1.05	$1.00	$0.73	$0.75	$0.75	$0.41	$0.34	$0.39	$0.40	$0.46	$0.45	$0.46	$0.47	$0.46	$0.52
PJM Administrative Fees	$0.23	$0.26	$0.71	$0.86	$1.05	$0.93	$0.72	$0.74	$0.72	$0.39	$0.31	$0.36	$0.37	$0.43	$0.42	$0.43	$0.43	$0.43	$0.48
NERC/RFC	$0.00	($0.00)	$0.01	$0.01	$0.01	$0.01	$0.01	($0.00)	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.03	$0.03	$0.03	$0.03
RTO Startup and Expansion	$0.00	$0.00	$0.00	$0.00	$0.00	$0.06	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.00	$0.00
Energy Uplift (Operating Reserves)	$0.52	$0.93	$1.27	$0.72	$0.89	$0.95	$1.07	$0.47	$0.65	$0.64	$0.48	$0.80	$0.78	$0.74	$0.55	$1.11	$0.38	$0.17	$0.14
Demand Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.03	$0.06	$0.05	$0.01	$0.03	$0.03	$0.03	$0.08	$0.08	$0.02	$0.01	$0.01
Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.03	$0.06	$0.05	$0.01	$0.01	$0.01	$0.02	$0.01	$0.03	$0.02	$0.01	$0.01
Emergency Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02	$0.01	$0.06	$0.06	$0.00	$0.00	$0.00
Emergency Energy	$0.07	$0.02	$0.00	$0.00	$0.02	$0.00	$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00
Total Price ($/MWh)	$38.92	$36.98	$43.22	$37.39	$47.83	$50.71	$69.81	$58.97	$71.25	$85.05	$55.66	$66.97	$63.28	$49.28	$53.93	$71.49	$56.87	$49.97	$53.24
Total Load (GWh)	259,623	264,510	265,398	312,899	327,533	438,874	684,592	696,165	715,524	698,459	666,069	697,391	723,101	764,300	773,790	780,505	776,093	778,269	758,775
Total Billing ($ Billions)	$10.10	$9.78	$11.47	$11.70	$15.67	$22.26	$47.79	$41.05	$50.98	$59.40	$37.08	$46.70	$45.76	$37.67	$41.73	$55.80	$44.14	$38.89	$40.40

58 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Table 1-11 shows the inflation adjusted average price, by component of the total wholesale power price per MWh, for calendar years 1999 through 2017.[59]

Table 1-11 Inflation adjusted total price per MWh by category: 1999 through 2017[60]

Category	1999 $/MWh	2000 $/MWh	2001 $/MWh	2002 $/MWh	2003 $/MWh	2004 $/MWh	2005 $/MWh	2006 $/MWh	2007 $/MWh	2008 $/MWh	2009 $/MWh	2010 $/MWh	2011 $/MWh	2012 $/MWh	2013 $/MWh	2014 $/MWh	2015 $/MWh	2016 $/MWh	2017 $/MWh
Load Weighted Energy	$33.04	$28.80	$33.45	$28.35	$36.24	$37.91	$52.37	$42.73	$48.06	$53.27	$29.46	$35.83	$33.01	$24.80	$26.82	$36.37	$24.69	$19.68	$20.43
Capacity	$0.13	$0.23	$0.24	$0.11	$0.07	$0.08	$0.03	$0.08	$2.77	$5.88	$8.12	$9.02	$7.46	$4.69	$5.06	$6.31	$7.66	$7.38	$7.43
Capacity	$0.13	$0.23	$0.24	$0.11	$0.07	$0.08	$0.02	$0.02	$2.73	$5.85	$8.11	$9.00	$6.99	$4.26	$4.94	$6.15	$7.58	$7.38	$7.40
Capacity (FRR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.38	$0.37	$0.07	$0.14	$0.09	$0.00	$0.00
Capacity (RMR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.06	$0.04	$0.03	$0.01	$0.01	$0.09	$0.06	$0.04	$0.03	($0.00)	($0.00)	$0.02
Transmission	$3.38	$3.88	$3.25	$3.10	$3.20	$2.93	$2.73	$2.68	$2.76	$2.87	$3.18	$3.21	$3.49	$3.74	$3.92	$4.41	$5.24	$5.67	$6.29
Transmission Service Charges	$3.31	$3.79	$3.17	$3.04	$3.13	$2.80	$2.24	$2.55	$2.69	$2.76	$3.04	$2.99	$3.23	$3.45	$3.61	$4.07	$4.84	$5.26	$5.82
Transmission Enhancement Cost Recovery	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.04	$0.08	$0.15	$0.20	$0.24	$0.25	$0.28	$0.34	$0.35	$0.42
Transmission Owner (Schedule 1A)	$0.07	$0.08	$0.07	$0.06	$0.06	$0.08	$0.07	$0.07	$0.07	$0.07	$0.06	$0.07	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.04	$0.41	$0.06	$0.00	$0.00	$0.00	$0.00	($0.00)	$0.00	$0.00	$0.00	$0.00	$0.00	($0.02)
Transmission Facility Charges	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Ancillary	$0.40	$0.64	$0.68	$0.56	$0.80	$0.77	$0.98	$0.74	$0.78	$0.86	$0.59	$0.66	$0.64	$0.59	$0.86	$0.67	$0.62	$0.48	$0.51
Reactive	$0.25	$0.27	$0.20	$0.18	$0.21	$0.22	$0.21	$0.23	$0.23	$0.25	$0.27	$0.33	$0.29	$0.32	$0.53	$0.27	$0.25	$0.26	$0.29
Regulation	$0.15	$0.37	$0.48	$0.38	$0.44	$0.43	$0.66	$0.42	$0.49	$0.52	$0.26	$0.27	$0.23	$0.18	$0.17	$0.22	$0.16	$0.07	$0.09
Black Start	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.01	$0.01	$0.03	$0.10	$0.05	$0.05	$0.06	$0.06
Synchronized Reserves	$0.00	$0.00	$0.00	$0.01	$0.13	$0.11	$0.09	$0.07	$0.05	$0.06	$0.04	$0.05	$0.07	$0.03	$0.03	$0.08	$0.08	$0.04	$0.04
Non-Synchronized Reserves	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01
Day Ahead Scheduling Reserve (DASR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.01	$0.04	$0.03	$0.04	$0.03	$0.07	$0.05	$0.03
Administration	$0.22	$0.24	$0.66	$0.77	$0.93	$0.85	$0.61	$0.60	$0.58	$0.31	$0.25	$0.29	$0.29	$0.33	$0.31	$0.32	$0.32	$0.31	$0.34
PJM Administrative Fees	$0.22	$0.25	$0.65	$0.77	$0.92	$0.79	$0.60	$0.59	$0.56	$0.29	$0.23	$0.27	$0.26	$0.30	$0.29	$0.29	$0.29	$0.29	$0.32
NERC/RFC	$0.00	($0.00)	$0.01	$0.01	$0.01	$0.01	$0.00	($0.00)	$0.01	$0.01	$0.01	$0.02	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
RTO Startup and Expansion	$0.00	$0.00	$0.00	$0.00	$0.00	$0.05	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.00	$0.00	$0.00
Energy Uplift (Operating Reserves)	$0.50	$0.87	$1.15	$0.65	$0.78	$0.81	$0.88	$0.38	$0.51	$0.48	$0.36	$0.59	$0.56	$0.52	$0.38	$0.77	$0.26	$0.12	$0.09
Demand Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.05	$0.03	$0.00	$0.02	$0.02	$0.02	$0.05	$0.05	$0.01	$0.01	$0.00
Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.05	$0.03	$0.00	$0.01	$0.01	$0.01	$0.01	$0.02	$0.01	$0.01	$0.00
Emergency Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.04	$0.04	$0.00	$0.00	$0.00
Emergency Energy	$0.07	$0.02	$0.00	$0.00	$0.02	$0.00	$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Price ($/MWh)	$37.75	$34.68	$39.44	$33.54	$42.04	$43.36	$57.63	$47.23	$55.51	$63.71	$41.97	$49.63	$45.48	$34.69	$37.41	$48.90	$38.81	$33.64	$35.10
Total Load (GWh)	259,623	264,510	265,398	312,899	327,533	438,874	684,592	696,165	715,524	698,459	666,069	697,391	723,101	764,300	773,790	780,505	776,093	778,269	758,775
Total Billing ($ Billions)	$9.80	$9.17	$10.47	$10.50	$13.77	$19.03	$39.45	$32.88	$39.72	$44.50	$27.95	$34.61	$32.88	$26.52	$28.95	$38.17	$30.12	$26.18	$26.63

59 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (October 11, 2018)
60 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Table 1-12 shows the percent of average price, by component of the wholesale power price per MWh, for calendar years 1999 through 2017.

Table 1-12 Percent of total price per MWh by category: 1999 through 2017[61]

Category	Percent of Total Charges 1999	Percent of Total Charges 2000	Percent of Total Charges 2001	Percent of Total Charges 2002	Percent of Total Charges 2003	Percent of Total Charges 2004	Percent of Total Charges 2005	Percent of Total Charges 2006	Percent of Total Charges 2007	Percent of Total Charges 2008	Percent of Total Charges 2009	Percent of Total Charges 2010	Percent of Total Charges 2011	Percent of Total Charges 2012	Percent of Total Charges 2013	Percent of Total Charges 2014	Percent of Total Charges 2015	Percent of Total Charges 2016	Percent of Total Charges 2017
Load Weighted Energy	87.5%	83.1%	84.8%	84.5%	86.2%	87.4%	90.9%	90.5%	86.5%	83.6%	70.1%	72.2%	72.6%	71.5%	71.7%	74.3%	63.6%	58.5%	58.2%
Capacity	0.4%	0.7%	0.6%	0.3%	0.2%	0.2%	0.1%	0.2%	5.0%	9.2%	19.4%	18.2%	16.4%	13.5%	13.5%	12.9%	19.8%	21.9%	21.2%
Capacity	0.4%	0.7%	0.6%	0.3%	0.2%	0.2%	0.0%	0.0%	4.9%	9.2%	19.4%	18.1%	15.4%	12.3%	13.2%	12.6%	19.6%	21.9%	21.1%
Capacity (FRR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capacity (RMR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.2%	0.2%	0.1%	0.1%	(0.0%)	(0.0%)	0.1%
Transmission	9.0%	11.2%	8.2%	9.3%	7.6%	6.8%	4.7%	5.7%	5.0%	4.5%	7.6%	6.5%	7.7%	10.8%	10.5%	9.0%	13.5%	16.9%	17.9%
Transmission Service Charges	8.8%	10.9%	8.0%	9.1%	7.5%	6.5%	3.9%	5.4%	4.8%	4.3%	7.2%	6.0%	7.1%	9.9%	9.7%	8.3%	12.5%	15.6%	16.6%
Transmission Enhancement Cost Recovery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%	0.3%	0.4%	0.7%	0.7%	0.6%	0.9%	1.0%	1.2%
Transmission Owner (Schedule 1A)	0.2%	0.2%	0.2%	0.2%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.2%	0.2%	0.1%	0.2%	0.2%	0.2%
Transmission Seams Elimination Cost Assignment (SECA)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	(0.0%)	0.0%	0.0%	0.0%	0.0%	0.0%	(0.0%)
Transmission Facility Charges	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Ancillary	1.1%	1.8%	1.7%	1.7%	1.9%	1.8%	1.7%	1.6%	1.4%	1.4%	1.4%	1.3%	1.4%	1.7%	2.3%	1.4%	1.6%	1.4%	1.5%
Reactive	0.7%	0.8%	0.5%	0.5%	0.5%	0.5%	0.4%	0.5%	0.4%	0.4%	0.7%	0.7%	0.6%	0.9%	1.4%	0.6%	0.7%	0.8%	0.8%
Regulation	0.4%	1.1%	1.2%	1.1%	1.1%	1.0%	1.1%	0.9%	0.9%	0.8%	0.6%	0.5%	0.5%	0.5%	0.5%	0.5%	0.4%	0.2%	0.3%
Black Start	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.3%	0.1%	0.1%	0.2%	0.2%
Synchronized Reserves	0.0%	0.0%	0.0%	0.0%	0.3%	0.3%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.1%	0.1%
Non-Synchronized Reserves	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Day Ahead Scheduling Reserve (DASR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%
Administration	0.6%	0.7%	1.7%	2.3%	2.2%	2.0%	1.1%	1.3%	1.0%	0.5%	0.6%	0.6%	0.6%	0.9%	0.8%	0.6%	0.8%	0.9%	1.0%
PJM Administrative Fees	0.6%	0.7%	1.7%	2.3%	2.2%	1.8%	1.0%	1.3%	1.0%	0.5%	0.6%	0.5%	0.6%	0.9%	0.8%	0.6%	0.8%	0.9%	0.9%
NERC/RFC	0.0%	(0.0%)	0.0%	0.0%	0.0%	0.0%	0.0%	(0.0%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%
RTO Startup and Expansion	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Energy Uplift (Operating Reserves)	1.3%	2.5%	2.9%	1.9%	1.9%	1.9%	1.5%	0.8%	0.9%	0.8%	0.9%	1.2%	1.2%	1.5%	1.0%	1.6%	0.7%	0.3%	0.3%
Demand Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%
Load Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Emergency Load Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%
Emergency Energy	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Price	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

61 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Figure 1-3 shows the contributions of load-weighted energy, capacity and transmission service charges to the total price of wholesale power for each quarter since 1999.

Figure 1-3 Top three components of quarterly total price ($/MWh): January 1999 through September 2018[62]

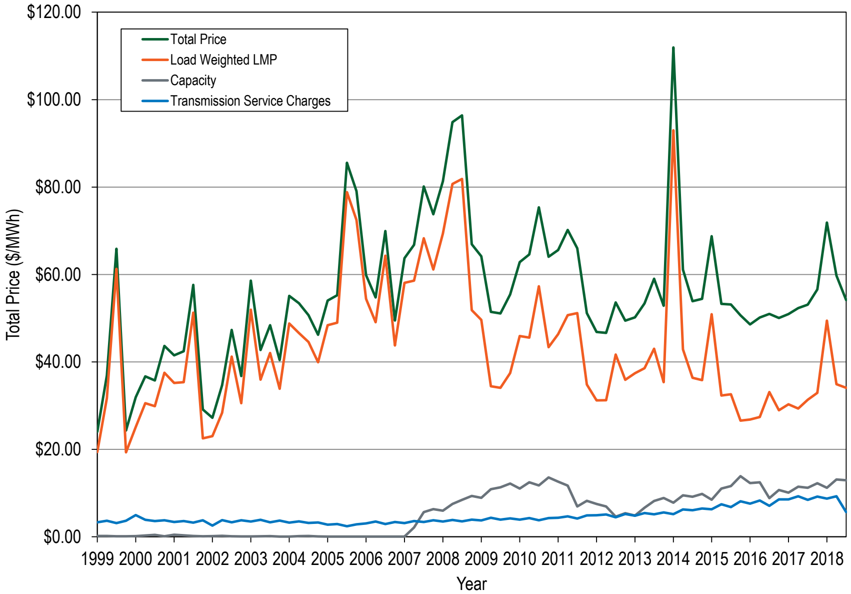
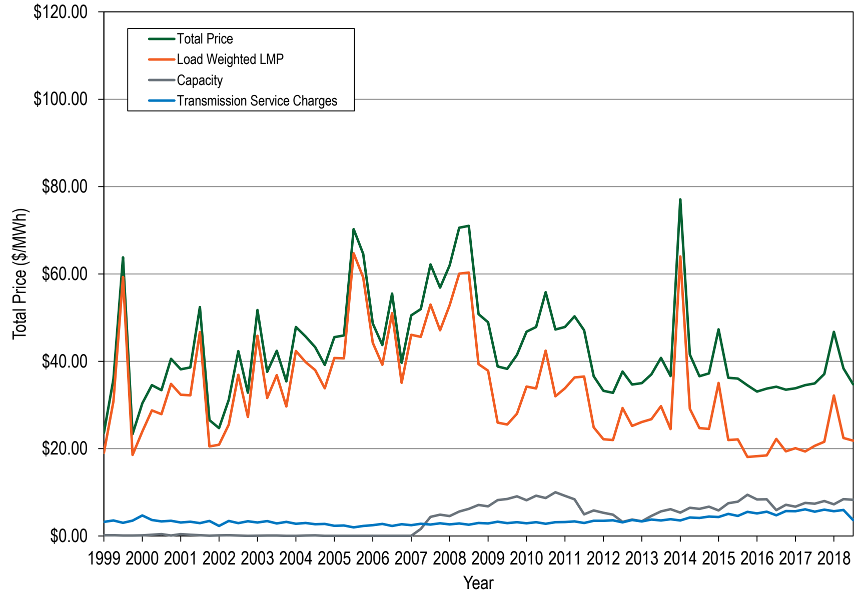


Figure 1-4 shows the inflation adjusted contributions of load-weighted energy, capacity and transmission service charges to the total price of wholesale power for each quarter since 1999.[63]

Figure 1-4 Inflation adjusted top three components of quarterly total price ($/MWh): January 1999 through September 2018[64]



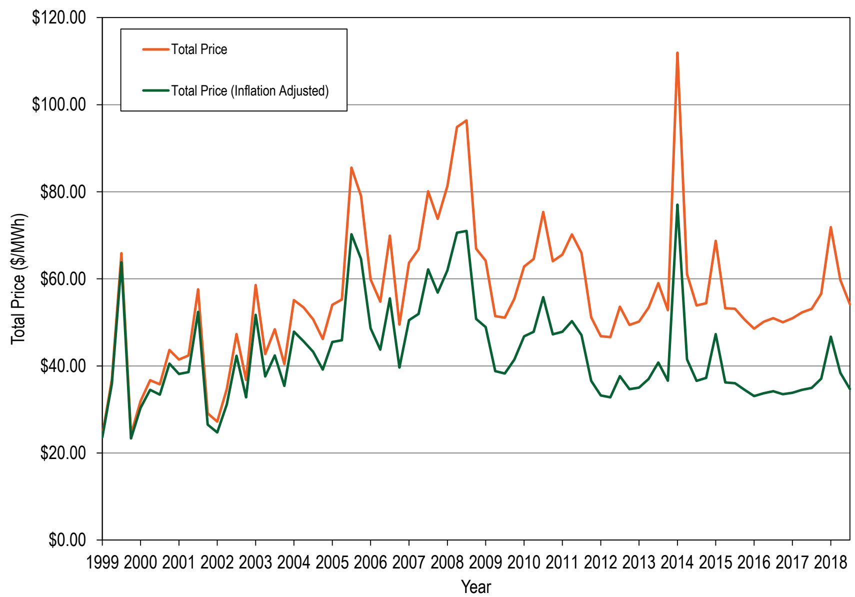
62 Note: The totals presented in this figure include after the fact billing adjustments and may not match totals presented in past reports.

63 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (October 11, 2018)

64 Note: The totals presented in this figure include after the fact billing adjustments and may not match totals presented in past reports.

Figure 1-5 shows the total price of wholesale power and the inflation adjusted total price of wholesale power for each quarter since 1999.[65]

Figure 1-5 Quarterly total price and quarterly inflation adjusted total price ($/MWh): January 1999 through September 2018[66 67]



65 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (October 11, 2018)
66 Note: The totals presented in this figure include after the fact billing adjustments and may not match totals presented in past reports.
67 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (October 11, 2018)

Section Overviews

Overview: Section 3, Energy Market

Market Structure

- **Supply.** Supply includes physical generation, imports and virtual transactions. The maximum average on peak hourly offered real-time supply was 114,869 MWh for the spring and 140,951 MWh for the summer. In the first nine months of 2018, 7,945.4 MW of new resources were added and 4,894.2 MW were retired.

  PJM average real-time cleared generation in the first nine months of 2018 increased by 4.3 percent from the first nine months of 2017, from 91,658 MWh to 95,561 MWh.

  PJM average day-ahead cleared supply in the first nine months of 2018, including INCs and up to congestion transactions, decreased by 13.0 percent from the first nine months of 2017, from 133,377 MWh to 116,068 MWh.

- **Aggregate Pivotal Suppliers.** The PJM energy market at times requires generation from pivotal suppliers to meet load, resulting in aggregate market power even when the HHI level indicates that the aggregate market is unconcentrated.

- **Generation Fuel Mix.** In the first nine months of 2018, coal units provided 29.2 percent, nuclear units 33.8 percent and natural gas units 30.7 percent of total generation. Compared to the first nine months of 2017, generation from coal units decreased 5.2 percent, generation from natural gas units increased 19.4 percent and generation from nuclear units decreased 0.2 percent.

- **Fuel Diversity.** In the first nine months of 2018, the fuel diversity of energy generation, measured by the fuel diversity index for energy (FDI_e), increased 0.7 percent over the FDI_e for the first nine months of 2017.

- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first nine months of 2018, coal units were 29.7 percent of marginal resources and natural gas units were 62.1 percent of marginal resources. In the first nine months of 2017, coal units were 32.5 percent and natural gas units were 52.9 percent of the marginal resources.

In the PJM Day-Ahead Energy Market, in the first nine months of 2018, up to congestion transactions were 63.9 percent of marginal resources, INCs were 9.2 percent of marginal resources, DECs were 16.1 percent of marginal resources, and generation resources were 10.7 percent of marginal resources. In the first nine months of 2017, up to congestion transactions were 80.4 percent of marginal resources, INCs were 5.5 percent of marginal resources, DECs were 10.1 percent of marginal resources, and generation resources were 4.0 percent of marginal resources.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM accounting peak load during the first nine months of 2018 was 147,042 MWh in the HE 1700 on August 28, 2018, which was 4,656 MWh, 3.3 percent, higher than the PJM peak load for the first nine months of 2017, which was 142,387 MWh in the HE 1800 on July 19, 2017.

  PJM average real-time demand in the first nine months of 2018 increased by 5.5 percent from the first nine months of 2017, from 87,243 MWh to 92,047 MWh. PJM average day-ahead demand in the first nine months of 2018, including DECs and up to congestion transactions, decreased by 13.1 percent from the first nine months of 2017, from 128,450 MWh to 111,589 MWh.

- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM do so using a combination of self-supply, bilateral market purchases and spot market purchases. For the first nine months of 2018, 12.8 percent of real-time load was supplied by bilateral contracts, 29.7 percent by spot market purchases and 58.6 percent by self-supply. Compared to the first nine months of 2017, reliance on bilateral contracts decreased by 1.6 percentage points, reliance on spot market purchases increased by 2.2 percentage points and reliance on self-supply decreased by 0.2 percentage points.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power when the rules are designed and implemented properly. Offer capping levels have historically been low in PJM. In the Day-Ahead Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.0 percent in the first nine months of 2017 to 0.1 percent in the first nine months of 2018. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.3 percent in the first nine months of 2017 to 1.0 percent in the first nine months of 2018. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation.

  In the first nine months of 2018, 14 control zones experienced congestion resulting from one or more constraints binding for 75 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to identify pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, including for reactive support. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours remained at 0.1 percent in the first nine months of 2017 and 2018. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours remained at 0.1 percent in the first nine months of 2017 and 2018.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the first nine months of

2018, in the PJM Real-Time Energy Market, 89.8 percent of marginal units had offer prices less than $50 per MWh. The average dollar markup of units with offer prices less than $25 was negative when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive when using unadjusted cost-based offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, demonstrating a revealed short run marginal cost that is less than the allowable cost-based offer under the PJM market rules. Some marginal units did have substantial markups. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the first nine months of 2018 was more than $500 per MWh while the highest markup in the first nine months of 2017 was more than $700 per MWh. During the period of cold weather and high demand in January, several units in the PJM market were offered with high markups.

In the first nine months of 2018, in the PJM Day-Ahead Energy Market, 95.2 percent of marginal generating units had offer prices less than $50 per MWh. The average dollar markup of units with offer prices less than $25 was negative when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive when using unadjusted cost-based offers. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the first nine months of 2018 was about $200 per MWh, while the highest markup in the first nine months of 2017 was about $50 per MWh.

- **Markup.** The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs.

  The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** A new FMU rule became effective November 1, 2014, limiting the availability of FMU adders to units with net revenues less than unit going forward costs. The number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero since December 2014.

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. In the first nine months of 2018, the average hourly increment offers submitted and cleared MW decreased by 32.3 percent and 47.0 percent, from 8,490 MW and 4,858 MW in the first nine months of 2017 to 5,746 MW and 2,577 MW in the first nine months of 2018. The average hourly decrement bids submitted and cleared MW decreased by 17.3 percent and 34.9 percent, from 8,318 MW and 4,380 MW in the first nine months of 2017 to 6,879 MW and 2,851 MW in the first nine months of 2018. The average hourly up to congestion submitted and cleared MW decreased by 58.8 percent and 48.4 percent, from 145,556 MW and 34,203 MW in the first nine months of 2017 to 60,036 MW and 17,639 MW in the first nine months of 2018.

- **Generator Offers.** Generator offers are categorized as dispatchable and self scheduled. Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are categorized as self scheduled. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are categorized as self scheduled and dispatchable. Of all generator offers by MW in the first nine months of 2018, 23.3 percent were offered as available for economic dispatch, 29.8 percent were offered at the economic minimum, 4.8 percent were offered as emergency dispatch, 17.5 percent were offered as self scheduled, and 23.5 percent were offered as self scheduled and dispatchable.

Market Performance

- **Prices.** PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emissions related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of closed loop interfaces related to demand side resources or reactive power, the application of transmission penalty factors, or the application of price setting logic.

  PJM real-time energy market prices increased in the first nine months of 2018 compared to the first nine months of 2017. The load-weighted, average real-time LMP was 29.9 percent higher in the first nine months of 2018 than in the first nine months of 2017, $39.43 per MWh versus $30.36 per MWh.

  PJM day-ahead energy market prices increased in the first nine months of 2018 compared to the first nine months of 2017. The load-weighted, average day-ahead LMP was 27.9 percent higher in the first nine months of 2018 than in the first nine months of 2017, $38.71 per MWh versus $30.26 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, in the first nine months of 2018, 19.8 percent of the load-weighted LMP was the result of coal costs, 39.2 percent was the result of gas costs and 0.76 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market, in the first nine months of 2018, 15.5 percent of the load-weighted LMP was the result of coal costs, 29.2 percent was the result of DEC bids, 18.6 percent was the result of gas costs, 18.1 percent was the result of INC offers, and 3.0 percent was the result of up to congestion transaction offers.

- **Markup.** The markup conduct of individual owners and units has an identifiable impact on market prices. Markup is a key indicator of the competitiveness of the energy market.

  In the PJM Real-Time Energy Market in the first nine months of 2018, the unadjusted markup component of LMP was $5.15 per MWh or 13.1 percent of the PJM load-weighted, average LMP. January had the highest unadjusted off peak markup component, $11.65 per MWh, or 13.28 percent of the real-time, off peak hour load-weighted, average LMP. There were 38 hours in the first nine months of 2018 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded $99.63 per MWh. During the period of cold weather and high demand in January, several units in the PJM market were offered with high markups.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In the first nine months of 2018, the unadjusted markup component of LMP resulting from generation resources was $0.67 per MWh or 1.7 percent of the PJM day-ahead load-weighted average LMP. January had the highest unadjusted peak markup component, $4.04 per MWh.

  Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the Day-Ahead and Real-Time Energy Markets, although the behavior of some participants represents economic withholding.

- **Price Convergence.** Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. The difference between the average day-ahead and real-time prices was -$0.11 per MWh in the first nine months of 2017 and $0.48 per MWh in the first nine months of 2018. The difference between average day-ahead and real-time prices, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Scarcity

- There were no five minute shortage pricing events in the first nine months of 2018. On May 29, 2018, there were six Performance Assessment Intervals (PAIs) triggered in the Edison area of the AEP Zone due to a localized load shed event. On July 18, 2018, there were 18 PAIs triggered in the Lonesome Pine area on the border of Virginia and West Virginia in the AEP Zone due to a localized load shed event to control for voltage violations.

Section 3 Recommendations

Market Power

- The MMU recommends that the market rules should explicitly require that offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate. The MMU recommends that the level of incremental costs includable in cost-based offers not exceed the short run marginal cost of the unit. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the tariff be changed to allow units to have Fuel Cost Policies that do not include fuel procurement practices, including fuel contracts. Fuel procurement practices, including fuel contracts, may be used as the basis for Fuel Cost Policies but should not be required. (Priority: Low. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends that PJM change the Fuel Cost Policy requirement to apply only to units that will be offered with non-zero cost-based offers. The PJM market rules should require that the cost-based offers of units without an approved Fuel Cost Policy be set to zero. (Priority: Low. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends that Manual 15 (Cost Development Guidelines) be replaced with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends revisions to the calculation of energy market opportunity costs to incorporate all time based offer parameters and all limitations that impact the opportunity cost of generating unit output. (Priority: Medium. First reported 2016. Status: Partially adopted.)

- The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the Day-Ahead Energy Market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be constant across the full MWh range of price and cost-based offers. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available price-based non-PLS offer, and that the price-MW pairs in the price-based PLS offer be exactly equal to the price-based non-PLS offer. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999, 2017.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)
- The MMU recommends that Market Sellers not be allowed to designate any portion of an available Capacity Resource's ICAP equivalent of cleared UCAP capacity commitment as a Maximum Emergency offer at any time during the delivery year.[68] (Priority: Medium. First reported 2012. Status: Not adopted.)

Capacity Performance Resources

- The MMU recommends that capacity performance resources and base capacity resources (during the June through September period) be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity performance construct. The operational parameters used by generation owners to indicate to PJM dispatchers what a unit is capable of during the operating day should not determine capacity performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the dispatcher to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not Adopted.)
- The MMU recommends that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs) in the capacity market default offer cap, and only include those events that trigger emergencies for at least a defined sub-zonal or zonal level. (Priority: Medium. New Recommendation. Status: Not adopted.)

68 This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See Schedule 1, Section 1.10.1A(d), Revisions to the PJM Open Access Transmission Tariff and PJM Operating Agreement (Marked/Redline Format), EL15-29-000 (December 12, 2014). FERC rejected the proposed change. See 151 FERC ¶ 61,208 at P 476 (2015).

- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. New Recommendation. Status: Not adopted.)

Accurate System Modeling

- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation; the use of constraint relaxation logic; and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. First reported 2015. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that the roles of PJM and the transmission owners in the decision making process to control for local contingencies be clarified, that PJM's role be strengthened and that the process be made transparent. (Priority: Low. First reported 2013. Status: Adopted, 2012.)
- The MMU recommends that PJM include in the tariff or appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[69] [70] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM increase the interaction of outage and operational restrictions data submitted by Market Participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)

Transparency

- The MMU recommends that PJM market rules require the fuel type be identified for every price and cost schedule and PJM market rules remove nonspecific fuel types such as other or co-fire other from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM continue to enhance its posting of market data to promote market efficiency. (Priority: Medium. First reported 2005. Status: Partially adopted.)

69 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

70 There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first nine months of 2018, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, participation in demand response programs, loads and prices.

PJM average real-time cleared generation increased by 3,902 MWh, 4.3 percent, and peak load increased by 4,656 MWh, 3.3 percent, in the first nine months of 2018 compared to the first nine months of 2017. The relationship between supply and demand, regardless of the specific market, balanced by market concentration and the extent of pivotal suppliers, is referred to as the supply-demand fundamentals or economic fundamentals. The market structure of the PJM aggregate energy market is partially competitive because aggregate market power does exist for a significant number of hours. The HHI is not a definitive measure of structural market power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. It is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. The current market power mitigation rules for the PJM energy market rely on the assumption that the ownership structure of the aggregate market ensures competitive outcomes. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not correct. There are pivotal suppliers in the aggregate energy market at times. High markups for some units demonstrate the potential to exercise market power during high demand conditions. The existing market power mitigation measures do not address aggregate market power. The MMU is developing an aggregate market power test and will propose market power mitigation rules to address aggregate market power.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[71] However, there are some issues with the application of market power mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test. These issues can be resolved by simple rule changes.

71 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.

The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. A competitive offer is equal to short run marginal costs. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, as interpreted by PJM, is not currently correct. Some unit owners include costs that are not short run marginal costs in offers, including maintenance costs. This issue can be resolved by simple rule changes to incorporate a clear and accurate definition of short run marginal costs.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost to serve load in each market interval. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in the first nine months of 2018 generally reflected supply-demand fundamentals, although the behavior of some participants during high demand periods represents economic withholding. Economic withholding is the ability to increase markups substantially in tight market conditions. There are additional issues in the energy market including the uncertainties about the pricing and availability of natural gas, the way that generation owners incorporate natural gas costs in offers, and the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel and operate rather than economically withhold or physically withhold.

Prices in PJM are not too low. There is no evidence to support the need for a significant change to the calculation of LMP. The underlying problem that fast start pricing and PJM's convex hull pricing approach are attempting to address is actually scarcity pricing, including the impact of operator actions on the definition of scarcity. Prices do not reflect market conditions when the market is tight. Rather than undercutting the basic LMP logic that is core to market efficiency, it would make more sense to directly address scarcity pricing, operator actions and the design of reserve markets. Targeted increases to the demand for reserves when the market is tight would address price formation in the energy market.

The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs would create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff would exist because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff would be created by PJM's fast start pricing proposal and in a much more extensive form by PJM's modified convex hull pricing proposal.

The fast start pricing and convex hull solutions would undercut LMP logic rather than directly addressing the underlying issues. The solution is not to accept that the inflexible CT should be paid or set price based on its commitment costs rather than its short run marginal costs. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why this unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying excess uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers based on measured reserve levels and transparent prices, that scarcity pricing only occurs when scarcity exists, and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. However, the explicit balancing mechanism that included net revenues directly in unit offers in the prior capacity market design is not present in the Capacity Performance design. The nature of a direct and explicit energy pricing net revenue true up mechanism in the capacity market should be addressed if energy revenues are expected to increase as a result of scarcity events, as a result of increased demand for reserves, or as a result of PJM's inappropriate proposals related to fast start pricing and the inclusion of maintenance expenses as short run marginal costs. The true up mechanism must address both cleared auctions and subsequent auctions. There are also significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on measured reserve levels (the current triggers are based on estimated reserves) and the lack of adequate locational scarcity pricing options.

The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case in the first nine months of 2018 or prior years. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during high demand periods represents economic withholding. Markups were higher in the first nine months of 2018, primarily as a result of markups during the cold weather in January. Given the structure of the energy market which can permit the exercise of aggregate market power at times of high demand, the change in some participants' behavior is a source of concern in the energy market and provides a reason to use correctly defined short run marginal cost as the sole basis for hourly changes in offers or offers greater than $1,000 per MWh. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2018.

Overview: Section 4, Energy Uplift

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges increased by $92.6 million, or 109.4 percent, in the first nine months of 2018 compared to the first nine months of 2017, from $84.6 million to $177.2 million.
- **Energy Uplift Charges Categories.** The increase of $92.6 million in the first nine months of 2018 is comprised of a $14.9 million increase in day-ahead operating reserve charges, a $79.3 million increase in balancing operating reserve charges and a $1.6 million decrease in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.052 per MWh, real-time load paid $0.047 per MWh, a DEC paid $0.739 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.709 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.052 per MWh, real-time load paid $0.043 per MWh, a DEC paid $0.761 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.709 per MWh.
- **Reactive Services Rates.** The ComEd, PENELEC, and EKPC control zones had the three highest local voltage support rates: $0.195, $0.036 and $0.025 per MWh.

Characteristics of Credits

- **Types of units.** Coal units received 61.9 percent of all day-ahead generator credits and 88.6 percent of all reactive service credits. Combustion turbines received 74.1 percent of all balancing generator credits. Combustion turbines and diesels received 74.0 percent of the lost opportunity cost credits.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 23.0 percent of all credits. The top 10 organizations received 75.6 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 7969, balancing operating reserves HHI was 2825 and lost opportunity cost HHI was 4642.
- **Economic and Noneconomic Generation.** In the first nine months of 2018, 84.9 percent of the day-ahead generation eligible for operating reserve credits was economic and 69.0 percent of the real-time generation eligible for operating reserve credits was economic.
- **Lost Opportunity Cost Credits.** Lost opportunity cost credits increased by $37.9 million or 382.7 percent, in the first nine months of 2018 compared to the first nine months of 2017, from $9.9 million to $47.8 million, as result of combustion turbines scheduled in day-ahead and not taken in real time.
- **Day-ahead generation not requested in real time.** Generation from combustion turbines and diesels scheduled day-ahead but not requested in real time receiving lost opportunity cost credits increased by 475 GWh or 109.8 percent in the first nine months of 2018, compared to the first nine months of 2017, from 433 GWh to 908 GWh.
- **Day-Ahead Unit Commitment for Reliability.** In the first nine months of 2018, 1.5 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 55.1 percent received energy uplift payments.

Geography of Charges and Credits

- In the first nine months of 2018, 88.3 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions (at control zones or buses within a control zone), demand and generation, 2.8 percent by transactions at hubs and aggregates and 8.9 percent by interchange transactions at interfaces.
- Generators in the Eastern Region received 48.6 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 49.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 1.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Section 4 Recommendations

- The MMU recommends that uplift should only be paid based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends that PJM not use closed loop interface constraints to artificially override nodal prices based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use CT price setting logic to modify transmission line limits to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that if PJM believes it appropriate to modify the LMP price setting logic, PJM initiate a stakeholder process to create transparent and consistent modifications to the rules and incorporate the modifications in the PJM tariff. (Priority: Medium. First Reported 2016. Status: Not adopted.)
- The MMU recommends that PJM initiate an analysis of the reasons why some combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not called in real time when they are economic. (Priority: Medium. First Reported 2012. Status: Not adopted.)
- The MMU recommends eliminating the use of intraday time segments to define eligibility for uplift payments and returning to evaluating the need for uplift on a daily, 24 hours, basis. (Priority: High. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends the elimination of the day-ahead operating reserve category to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2009. Status: Not adopted. Stakeholder process.)
- The MMU recommends not compensating self scheduled units for their startup cost when the units are scheduled by PJM to start before the self scheduled hours. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends four modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods for combustion turbines and diesels scheduled in the Day-Ahead Energy Market, but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)

- The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time be compensated for LOC incurred within an hour. (Priority: Medium. First reported 2013. Status: Adopted.)
- The MMU recommends that only flexible fast start units (startup plus notification times of 10 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the Day-Ahead Energy Market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)

- The MMU recommends that up to congestion transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Not adopted.
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. (Priority: High. First reported 2013. Status: Adopted 2018.)
- The MMU recommends allocating the energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the operating reserve credits calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, which is currently allocated solely to real-time RTO load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM allow wind units to submit CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM revise Manual 11 attachment C consistent with the tariff to limit uplift compensation to offered costs. The Manual 11 attachment C procedure should describe the steps market participants must take to change the availability of cost-based energy offers that have been submitted day ahead. The MMU recommends that PJM eliminate the Manual 11 attachment C procedure with the implementation of hourly offers (ER16-372-000). (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring operating reserves in the Day-Ahead and the Real-Time Energy Markets and the associated operating reserve charges in order to make all market participants aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves. (Priority: Medium. First reported 2011. Status: Partially Adopted.)
- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete

information about the level of operating reserve charges by unit and the detailed reasons for the level of operating reserve credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Partially adopted.)

- The MMU recommends that the lost opportunity cost in the energy market be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2012. Status: Adopted 2015.)
- The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. (Priority: Medium. First reported 2012. Status: Adopted 2015.)
- The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost. (Priority: Medium. First reported 2012. Status: Adopted 2015.)
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends implementation of a metric to define when a unit is following dispatch to determine eligibility to receive balancing operating reserve credits. (Priority: Medium. First reported Q1, 2018. Status: Not adopted.)

Section 4 Conclusion

Competitive market outcomes result from energy offers equal to short run marginal costs and that incorporate flexible operating parameters. But when PJM permits a unit to include inflexible operating parameters in its offer and pays uplift based on those inflexible parameters, there is an incentive for the unit to remain inflexible. The rules regarding operating parameters should be implemented in a way that creates incentives for flexible operations rather than inflexible operations. The standard for paying uplift should be the maximum achievable flexibility, based on OEM standards for the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. Applying a weaker standard effectively subsidizes inflexible units by paying them based on inflexible parameters that result from lack of investment and that could be made more flexible. The result both inflates uplift costs and suppresses energy prices.

It is not appropriate to accept that inflexible units should be paid or set price based on short run marginal costs plus no load. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why the inflexible unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

The reduction of uplift payments should not be a goal to be achieved at the expense of the fundamental logic of the LMP system. For example, the use of closed loop interfaces to reduce uplift should be eliminated because it is not consistent with LMP fundamentals and constitutes a form of subjective price setting. The same is true of what PJM terms its CT price setting logic. The same is true of fast start pricing and of convex hull pricing.

Accurate short run price signals, equal to the short run marginal cost of generating power, provide market incentives for cost minimizing production to all economically dispatched resources and provide market incentives to load based on the marginal cost of additional consumption. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs would create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff would exist because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff would be created in more limited form by PJM's fast start pricing proposal (limited convex hull pricing) and in extensive form by PJM's full convex hull pricing proposal.

When units receive substantial revenues through energy uplift payments, these payments are not transparent to the market because of the current confidentiality rules. As a result, other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations have persisted for more than ten years.

One part of addressing the level and allocation of uplift payments is to eliminate all day-ahead operating reserve credits. It is illogical and unnecessary to pay units day-ahead operating reserve credits because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve credits.

Up to congestion transactions continue to pay no energy uplift charges, which means that all others who pay these charges are paying too much. In addition, the netting of transactions against internal bilateral transactions should be eliminated.[72]

PJM needs to pay substantially more attention to the details of uplift payments including accurately tracking whether units are following dispatch, identifying the actual need for units to be dispatched out of merit and determining whether local reserve zones or better definitions of constraints would be a more market based approach.

While energy uplift charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of these charges are as low as possible consistent with the reliable operation of the system and consistent with pricing at short run marginal cost. The goal should be to minimize the total incurred energy uplift charges and to increase the transactions over which those charges are spread in order to reduce the impact of energy uplift charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets.

72 On October 17, 2017, PJM filed with FERC to begin charging uplift to UTC transactions and eliminating the netting of deviations with internal bilateral transactions. As of November 1, 2018, internal bilateral transaction will no longer be assessed deviations. See FERC Docket No. ER18-86-000.

Overview: Section 5, Capacity Market

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[73]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for Delivery Years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each Delivery Year.[74] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the Delivery Year.[75] Also effective for the 2012/2013 Delivery Year, a Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant Delivery Year.[76]

73 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.
74 See 126 FERC ¶ 61,275 at P 86 (2009).
75 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
76 See 126 FERC ¶ 61,275 at P 88 (2009)

The 2018/2019 RPM Third Incremental Auction, the 2021/2022 RPM Base Residual Auction, the 2019/2020 RPM Second Incremental Auction, and the 2020/2021 RPM First Incremental Auction were conducted in the first nine months of 2018.

On June 9, 2015, FERC accepted changes to the PJM capacity market rules proposed in PJM's Capacity Performance (CP) filing.[77] For a transition period during the 2018/2019 and 2019/2020 Delivery Years, PJM will procure two product types, Capacity Performance and Base Capacity. PJM also procured Capacity Performance resources in two transition auctions for the 2016/2017 and 2017/2018 Delivery Years. Effective with the 2020/2021 Delivery Year, PJM will procure a single capacity product, Capacity Performance. CP Resources are expected to be available and capable of providing energy and reserves when needed at any time during the Delivery Year.[78] Effective for the 2018/2019 through the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint are established for each modeled LDA. These maximum quantities are set for reliability purpose to limit the quantity procured of the less available products, including Base Capacity Generation Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources. The Capacity Performance (CP) Transition Incremental Auctions (IAs) were held as part of a five year transition to a single capacity product type in the 2020/2021 Delivery Year. Participation in the CP Transition IAs was voluntary. If a resource cleared a CP Transition IA and had a prior commitment for the relevant delivery year, the existing commitment was converted to a CP commitment, which is subject to the CP performance requirements and nonperformance charges. The Transition IAs were not designed to minimize the cost of purchasing Capacity Performance resources for the two delivery years and were not designed to maximize economic welfare for the two delivery years.

RPM prices are locational and may vary depending on transmission constraints.[79] Existing generation capable of qualifying as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity, and the performance incentives have been strengthened significantly under the Capacity Performance modifications to RPM. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power based on the marginal cost of capacity, that define offer caps, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Market power mitigation is effective only when these definitions are up to date and accurate. Demand resources and energy efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **RPM Installed Capacity.** During the first nine months of 2018, RPM installed capacity decreased 677.1 MW or 0.4 percent, from 183,882.4 MW on January 1 to 184,559.5 MW on September 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on September 30, 2018, 39.6 percent was gas; 33.1 percent was coal; 17.7 percent was nuclear; 4.8 percent was hydroelectric; 3.5 percent was oil; 0.6 percent was wind; 0.4 percent was solid waste; and 0.3 percent was solar.
- **Market Concentration.** In the 2019/2020 RPM Second Incremental Auction and the 2020/2021 RPM First Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[80] Offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not

77 See 151 FERC ¶ 61,208 (2015).

78 See "PJM Manual 18: PJM Capacity Market," Rev. 40 (Feb.22, 2018) at 19.

79 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

80 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given delivery year using the rules defined in OATT Attachment DD § 5.10(a)(ii).

pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[81] [82] [83]

- **Imports and Exports.** Of the 4,470.4 MW of imports in the 2021/2022 RPM Base Residual Auction, 4,051.8 MW cleared. Of the cleared imports, 1,909.9 MW (47.1 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 10,798.7 MW for June 1, 2018, as a result of cleared capacity for demand resources and energy efficiency resources in RPM Auctions for the 2018/2019 Delivery Year (13,731.7 MW) less replacement capacity (2,933.0 MW).

Market Conduct

- **2019/2020 RPM Second Incremental Auction.** Of the 72 generation resources that submitted Base Capacity offers, the MMU calculated unit specific offer caps for eight generation resources (11.1 percent). Of the 409 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for six generation resources (1.5 percent).
- **2021/2022 RPM Base Residual Auction.** The conduct of some participants was determined to be not competitive.
- **2020/2021 RPM First Incremental Auction.** Of the 397 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for eight generation resources (2.0 percent).

Market Performance

- The 2018/2019 RPM Third Incremental Auction, the 2021/2022 RPM Base Residual Auction, the 2019/2020 RPM Second Incremental Auction, and the 2020/2021 RPM First Incremental Auction were conducted in the first nine months of 2018. The weighted average capacity price for the 2018/2019 Delivery Year is $172.09, including all RPM auctions for the 2018/2019 Delivery Year held through the first nine months of 2018. The weighted average capacity price for the 2019/2020 Delivery Year is $112.63, including all RPM auctions for the 2019/2020 Delivery Year held through the first nine months of 2018.
- For the 2018/2019 Delivery Year, RPM annual charges to load are $11.0 billion.
- In the 2021/2022 RPM Base Residual Auction, market performance was determined to be not competitive as a result of noncompetitive offers that affected market results.

Reliability Must Run Service

- Of the seven companies (23 units) that have provided RMR service, two companies (seven units) filed to be paid for RMR service under the deactivation avoidable cost rate (DACR), the formula rate. The other five companies (16 units) filed to be paid for RMR service under the cost of service recovery rate.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for the first nine months of 2018 was 7.2 percent, an increase from 6.9 percent for the first nine months of 2017.[84]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for the first nine months of 2018 was 84.4 percent, a decrease from 85.5 percent for the first nine months of 2017.
- **Outages Deemed Outside Management Control (OMC).** In the first nine months of 2018, 1.1 percent of forced outages were classified as OMC outages.

81 See OATT Attachment DD § 6.5.
82 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
83 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).
84 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. This set of capacity resources may include generators in addition to those in the set of generators committed as capacity resources in RPM. Data was downloaded from the PJM GADS database on October 25, 2018. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

Section 5 Recommendations[85]

The MMU recognizes that PJM has implemented the Capacity Performance Construct to replace some of the existing core market rules and to address fundamental performance incentive issues. The MMU recognizes that the Capacity Performance Construct addresses many of the MMU's recommendations. The MMU's recommendations are based on the existing capacity market rules. The status is reported as adopted if the recommendation was included in FERC's order approving PJM's Capacity Performance filing.[86]

Definition of Capacity

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant Delivery Year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[87] [88] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that the definition of demand side resources be modified to ensure that such resources be fully substitutable for other generation capacity resources. Both the Limited and the Extended Summer DR products should be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as generation capacity resources. (Priority: High. First reported 2012. Status: Adopted 2015.)

85 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 52.
86 151 FERC ¶ 61,208 (2015).
87 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
88 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).

Market Design and Parameters

- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[89] [90] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that energy efficiency resources (EE) not be included on the supply side of the capacity market, because PJM's load forecasts now account for future EE, unlike the situation when EE was first added to the capacity market. However, the MMU recommends that the PJM load forecast method should be modified so that EE impacts immediately affect the forecast without the long lag times incorporated in the current forecast method. If EE is not included on the supply side, there is no reason to have an add back mechanism. If EE remains on the supply side, the implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)

89 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").
90 See the *2017 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

- The MMU recommends that the use of the 2.5 percent demand adjustment (Short Term Resource Procurement Target) be terminated immediately. The 2.5 percent should be added back to the overall market demand curve. (Priority: Medium. First reported 2013. Status: Adopted 2015.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. The current nested LDA structure used in the capacity market does not adequately represent all the capacity transfers that are feasible among LDAs. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a nonnested model for all LDAs and specify a VRR curve for each LDA separately. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should price separate if that is the result of the LDA supply curves and the transmission constraints. (Priority: Medium. First reported 2017. Status: Not adopted.)

Offer Caps and Offer Floors

- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[91] (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[92] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that modifications to existing resources not be treated as new resources for purposes of market power related offer caps or MOPR offer floors. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make whole payments. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM develop a forward looking estimate for the expected number of Performance Assessment Intervals (H) to use in calculating the Non-Performance Charge Rate. The MMU recommends that PJM develop a forward looking estimate for the Balancing Ratio (B) during Performance Assessment Intervals (PAIs) to use in calculating the default offer cap. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction, and should incorporate the actual observed reserve margins, and other assumptions consistent with the annual IRM study. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that when expected H and B are not the same as the assumed levels used to calculate the default market seller offer cap of Net CONE times B, the offer cap be recalculated for each BRA using the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that capacity market sellers be required to request the use of minimum MW quantities greater than 0 MW (inflexible sell offer segments) and that the requests should only be permitted for defined physical reasons. (Priority: Medium. New recommendation. Status: Not adopted.)

91 Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000,-001; EL18-178 (October 2, 2018).

92 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

Performance Incentive Requirements of RPM

- The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAH not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that generation capacity resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. One hundred percent of capacity market revenue should be at risk rather than only fifty percent. (Priority: High. First reported 2012. Status: Adopted 2015.)
- The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market. (Priority: Medium. First reported 2013. Status: Adopted 2015.)
- The MMU recommends that PJM eliminate the broad exception related to lack of gas during the winter period for single-fuel, natural gas fired units.[93] (Priority: Medium. First reported 2013. Status: Adopted 2015.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability. (Priority: High. First reported 2016. Status: Not adopted.)

93 See OATT Attachment DD § 10(e). For more on this issue and related incentive issues, see the MMU's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, joint report, "*Capacity in the PJM Market*," (August 20, 2012). <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf>.

- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all capacity imports have firm transmission to the PJM border prior to offering in an RPM auction. (Priority: High. First reported 2014. Status: Adopted 2015.)
- The MMU recommends that all resources importing capacity into PJM accept a must offer requirement. (Priority: High. First reported 2014. Status: Adopted 2015.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. PJM has modified these rules, but the rules need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that RMR units recover all and only the incremental costs, including incremental investment costs, required by the RMR service that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Customers should bear no responsibility for paying previously incurred costs, including a return on or of prior investments. (Priority: Low. First reported 2010. Status: Not adopted.)

- The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V. The MMU also recommends specific improvements to the DACR provisions. (Priority: Medium. First reported 2017. Status: Not adopted.)

Section 5 Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The MMU concludes that the 2021/2022 RPM Base Residual Auction results were not competitive as a result of offers above the competitive level by some market participants. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the non-performance charge rate is defined as Net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions.

The FERC approved PJM tariff defines the offer cap as Net CONE times B, rather than including the full logic supporting the definition of the offer cap under the capacity performance paradigm. If the tariff had defined the offer cap consistent with PJM's filing in the capacity performance matter, the offer cap would have been net ACR rather than Net CONE times B.

The MMU is required to identify market issues and to report them to the Commission and to market participants. The Commission decides on any action related to the MMU's findings.

The MMU found serious market structure issues, measured by the three pivotal supplier test results in the PJM Capacity Market in the first nine months of 2018. Explicit market power mitigation rules in the RPM construct only partially offset the underlying market structure issues in the PJM Capacity Market under RPM. In the 2021/2022 RPM Base Residual Auction, the default offer cap of net CONE times B exceeded the competitive offer for a number of resources. Some seasonal resources were paid additional make whole based on a failure of the market power rules to apply offer capping.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[94] [95] [96] [97] [98][99] [100] In 2017 and 2018, the MMU prepared a number of RPM-related reports and testimony, shown in Table 5-2. The capacity performance modifications to the RPM construct have significantly improved the capacity market and addressed many of the issues identified by the MMU. The MMU will publish more detailed reports on the CP auctions which include more specific issues and suggestions for improvements.

The PJM markets have worked to provide incentives to entry and to retaining capacity. PJM has excess reserves of more than 9,000 MW on June 1, 2018, and will have excess reserves of more than 14,000 MW on June 1, 2019, based on current positions. Capacity investments in PJM were financed by market sources. Of the 30,881.7 MW of additional capacity that cleared in

94 See "Analysis of the 2017/2018 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_2017_2018_RPM_Base_Residual_Auction_20141006.pdf> (October 6, 2014).
95 See "Analysis of the 2018/2019 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf> (July 6, 2016).
96 See "Analysis of the 2019/2020 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf> (August 31, 2016).
97 See "Analysis of the 2020/2021 RPM Base Residual Auction," <<http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf>> (November 11, 2017).
98 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <<http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf>> (August 24, 2018).
99 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2016," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_06012007_to_06012016_20161227.pdf> (December 27, 2016).
100 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).

RPM auctions for the 2007/2008 through 2017/2018 delivery years, 22,419.7 MW (72.6 percent) were based on market funding. Of the 13,553.8 MW of additional capacity that cleared in RPM auctions for the 2018/2019 through 2021/2022 delivery years, 11,752.4 MW (86.7 percent) are based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

The issue of external subsidies emerged more fully in 2017 and the first nine months of 2018. The subsidies are not part of the PJM market design but nonetheless threaten the foundations of the PJM capacity market as well as the competitiveness of PJM markets overall.

The Ohio subsidy proceedings, the Illinois ZEC legislation to subsidize the Quad Cities nuclear power plant, the request in Pennsylvania to subsidize the Three Mile Island nuclear power plant, the New Jersey legislation to subsidize the Salem and Hope Creek nuclear power plants, the potential U.S. DOE proposal to subsidize coal and nuclear power plants, and the request by FirstEnergy to the U.S. DOE for subsidies consistent with the DOE Grid Resilience Proposal, all originate from the fact that competitive markets result in the exit of uneconomic and uncompetitive generating units. Regardless of the specific rationales offered by unit owners, the proposed solution for all such generating units has been to provide out of market subsidies in order to retain such units. The proposed solution in all cases ignores the opportunity cost of subsidizing uneconomic units, which is the displacement of new resources and technologies that would otherwise be economic. These subsidies are not accurately characterized as state subsidies. These subsidies were all requested by the owners of specific uneconomic generating units in order to improve the profitability of those specific units. These subsidies were not requested to accomplish broader social goals. Broader social goals can all be met with market-based mechanisms available to all market participants on a competitive basis and without discrimination.

Subsidies are contagious. Competition in the markets could be replaced by competition to receive subsidies. Similar threats to competitive markets are being discussed by unit owners in other states and the potentially precedential nature of these actions enhances the urgency of creating an effective rule to maintain competitive markets by modifying market rules to address these subsidies.

PJM markets have no protection against this emergent threat. Accurate signals for entry and exit are necessary for well functioning and competitive markets. Competitive investors rely on accurate signals to make decisions. The current MOPR only addresses subsidies for new entry. The current subsidies demonstrate that the markets need protection against subsidized, noncompetitive offers from existing as well as new resources. The MOPR should be extended to address subsidies for existing units, and this should be done expeditiously.

While a MOPR that includes existing units would protect markets in the short run, the underlying issues that have resulted in the pressure on markets should also be examined. Unit owners are seeking subsidies because gas prices are low resulting in low energy market margins and because flaws in the PJM capacity design have led to very substantial price suppression over the past 10 years.

To the extent that there are shared broader goals related to PJM markets, they should also be addressed, but this can happen with a slightly longer lead time. If a shared goal is to reduce carbon output, a price on carbon is the market based solution. If a shared goal is increased renewables in addition to their carbon attributes, a common approach to RECs would be a market based solution. Fuel diversity has also been mentioned as an issue. Current fuel diversity is higher than ever in PJM. If there is an issue, the real issue is fuel security and not fuel diversity. Significant reliance on specific fuels, including nuclear, coal and gas means that markets are at risk from a significant disruption in any one fuel. If fuel security for gas is a concern, a number of issues should be considered including the reliability of the pipelines, the compatibility of the gas pipeline and the merchant generator business models, the degree to which electric generators have truly firm gas service and the need for a gas RTO to help ensure reliability.

As a result of the fact that demand side resources have contributed to price suppression in PJM capacity markets, the place of demand side in PJM should be reexamined. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation. There are other price formation issues in the capacity market that should also be examined and addressed.

Overview: Section 6, Demand Response

- **Demand Response Activity.** Demand response activity includes economic demand response (economic resources), emergency and pre-emergency demand response (demand resources), synchronized reserves and regulation. Economic demand response participates in the energy market. Emergency and pre-emergency demand response participates in the capacity market and energy market.[101] Demand response resources participate in the Synchronized Reserve Market. Demand response resources participate in the regulation market.

  In the first nine months of 2018, total demand response revenue increased by $64.0 million, 17.2 percent, from $371.1 million in the first nine months of 2017 to $435.1 million in the first nine months of 2018. Emergency demand response revenue accounted for 98.0 percent of all demand response revenue, economic demand response for 0.5 percent, demand response in the Synchronized Reserve Market for 1.0 percent and demand response in the regulation market for 0.5 percent.

  Total emergency demand response revenue increased by $60.9 million, 16.7 percent, from $365.4 million in the first nine months of 2017 to $426.3 million in the first nine months of 2018. This increase consisted entirely of capacity market revenue.[102]

  Economic demand response revenue increased by $101.2 thousand, 4.7 percent, from $2,167.6 thousand in the first nine months of 2017 to $2,268.7 thousand in the first nine months of 2018.[103] Demand response revenue in the Synchronized Reserve Market increased by $2.0 million, 87.3 percent, from $2.3 million in the first nine months of 2017 to $4.2 million in the first nine months of 2018. Demand response revenue in the regulation market increased by $1.0 million, 78.5 percent, from $1.3 million in the first nine months of 2017 to $2.3 million in the first nine months of 2018.

- **Demand Response Energy Payments are Uplift.** Energy payments to emergency and economic demand response resources are uplift. LMP does not cover energy payments although emergency and economic demand response can and does set LMP. Energy payments to emergency demand resources are paid by PJM market participants in proportion to their net purchases in the real-time market. Energy payments to economic demand resources are paid by real-time exports from PJM and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than or equal to the net benefits test price for that month.[104]

- **Demand Response Market Concentration.** The ownership of economic demand response resources was highly concentrated in the first nine months of 2017 and 2018. The HHI for economic resource reductions increased from 7590 in the first nine months of 2017 to 7705 in the first nine months of 2018. The ownership of emergency demand response resources was moderately concentrated in the first nine months of 2018. The HHI for emergency demand response committed MW was 1433 for the 2017/2018 Delivery Year and 1922 for the 2018/2019 Delivery Year. In the 2017/2018 Delivery Year, the four largest companies contributed 69.6 percent of all committed emergency demand response MW. In the 2018/2019 Delivery Year, the four largest companies contributed 77.9 percent of all committed emergency demand response MW.

- **Limited Locational Dispatch of Demand Resources.** Beginning with the 2014/2015 Delivery Year, demand resources are dispatchable for mandatory reductions on a subzonal basis, defined by zip codes, but only if the subzone is defined at least one day before it is dispatched and only until PJM removes the definition of the subzone. Nodal dispatch of demand resources in a nodal market would improve market efficiency.

101 Emergency demand response refers to both emergency and pre-emergency demand response. With the implementation of the Capacity Performance design, there is no functional difference between the emergency and pre-emergency demand response resource.
102 The total credits and MWh numbers for demand resources were calculated as of October 11, 2018 and may change as a result of continued PJM billing updates.
103 Economic credits are synonymous with revenue received for reductions under the economic load response program.
104 "PJM Manual 28: Operating Agreement Accounting," Rev. 80 (June. 1, 2018) at 83.

The goal should be nodal dispatch of demand resources with no advance notice required, as is the case for generation resources.

Section 6 Recommendations

The MMU recognizes that PJM incorporated some of the recommendations related to demand response in the Capacity Performance filing. The status of each recommendation reflects the status at September 30, 2018.

- The MMU recommends, as a preferred alternative to including demand resources as supply in the capacity market, that demand resources be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)
- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as an economic resource, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Interval. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[105] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[106] (Priority: Medium. First reported 2013. Status: Not adopted.)

105 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

106 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed October 17, 2017) ISO-NE requires that DR have an interval meter with five-minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance for the base and capacity performance products. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for all hours of the year. (Priority: High. First reported 2011. Status: Partially adopted.[107])
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends setting the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. First reported 2017. Status: Partially adopted.)
- The MMU recommends that PRD be required to respond during a PAH to be consistent with all CP resources. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends capping the baseline for measuring compliance under GLD, for the limited summer product, at the customers' PLC. (Priority: High. First reported 2010. Status: Adopted 2015.)
- The MMU recommends that demand resources whose technology type (load drop method) is designated as "Other" explicitly record the technology type. (Priority: Low. First reported 2013. Status: Adopted 2014.)

Section 6 Conclusion

A fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real-time energy price signals in real time, will have the ability to react to real-time prices in real time and will have the ability to receive the direct benefits or costs of changes in real-time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity in the same year in which demand for capacity changes. A functional demand side of these markets means that customers will have the ability to make decisions about levels of power consumption based both on the value of the uses of the power and on the actual cost of that power.

107 PJM's Capacity Performance proposal includes this change. See "Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA")," Docket No. ER15-632-000 and "PJM Interconnection, L.L.C." Docket No. EL15-29-000.

In the energy market, if there is to be a demand side program, demand resources should be paid the value of energy, which is LMP less any generation component of the applicable retail rate. There is no reason to have the net benefits test. The necessity for the net benefits test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they suppress market prices, but that customers can choose not to consume at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not purchase power and the market impact of that choice does not require a test for appropriateness.

If demand resources are to continue competing directly with generation capacity resources in the PJM Capacity Market, the product must be defined such that it can actually serve as a substitute for generation. This is a prerequisite to a functional market design. The Capacity Performance demand response product definition in the PJM Capacity Performance capacity market design is a significant step in that direction, although performance obligations are still not identical to other capacity resources.

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic resource, as generation is defined. Demand resources should be required to offer in the Day-Ahead Energy Market and should be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year. The fact that PJM currently defines demand resources as emergency resources and the fact that calling on demand resources triggers a performance assessment interval (PAI) under the Capacity Performance design, both serve as a significant disincentive to calling on demand resources. Demand resources should be treated as economic resources like any other capacity resource. Demand resources should be called when economic and paid the LMP rather than an inflated strike price up to $1,849 per MWh that is set by the seller.

In order to be a substitute for generation, demand resources should be subject to robust measurement and verification techniques to ensure that transitional DR programs incent the desired behavior. The methods used in PJM programs today are not adequate to determine and quantify deliberate actions taken to reduce consumption.

In order to be a substitute for generation, demand resources should provide a nodal location and should be dispatched nodally to enhance the effectiveness of demand resources and to permit the efficient functioning of the energy market. Both subzonal and multi-zone compliance should be eliminated because they are inconsistent with an efficient nodal market.

In order to be a substitute for generation, compliance by demand resources to PJM dispatch instructions should include both increases and decreases in load. The current method applied by PJM simply ignores increases in load and thus artificially overstates compliance.

In order to be a substitute for generation, reductions should be calculated hourly for dispatched DR. The current rules use the average reduction for the duration of an event. The average reduction across multiple hours does not provide an accurate metric for each hour of the event and is inconsistent with the measurement of generation resources. Measuring compliance hourly would provide accurate information to the PJM system. Under the new CP rules, the performance of demand response during Performance Assessment Interval (PAI) will be measured on an hourly basis.

In order to be a substitute for generation, any demand resource and its Curtailment Service Provider (CSP), should be required to notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at the specified level, such as in the case of bankrupt and out of service facilities. Generation resources are required to inform PJM of any change in availability status, including outages and shutdown status.

As a preferred alternative, demand response resources should be on the demand side of the capacity market rather than on the supply side. Rather than detailed demand response programs with their attendant complex and difficult to administer rules, customers would be able to avoid capacity and energy charges by not using capacity and energy at their discretion and the level of usage paid for would be defined by metered usage rather than a complex and inaccurate measurement protocol.

The current proposals at the Summer-Only Demand Response Senior Task Force (SODRSTF) are an example of how to create a demand side product that is on the demand side of the market and not on the supply side. Under the MMU proposal, load would agree to curtail demand to at or below a defined FSL, less than the customer PLC, when the THI exceeds a defined level or load exceeds a specified threshold.[108] PJM will incorporate the associated load reduction in the load forecast. By relying on metered load and the PLC, load can reduce its demand for capacity and that reduction can be verified without complicated and inaccurate metrics to estimate load reductions.[109] Other proposals would continue to rely on load estimates rather than metered load to calculate actual demand.

The long term appropriate end state for demand resources in the PJM markets should be comparable to the demand side of any market. Customers should use energy as they wish and that usage will determine the amount of capacity and energy for which each customer pays. There would be no counterfactual measurement and verification.

Under this approach, customers that wish to avoid capacity payments would reduce their load during expected high load hours. Capacity costs would be assigned to LSEs and by LSEs to customers, based on actual load on the system during these critical hours. Customers wishing to avoid high energy prices would reduce their load during high price hours. Customers would pay for what they actually use, as measured by meters, rather than relying on flawed measurement and verification methods. No M&V estimates are required. No promises of future reductions which can only be verified by M&V are required. To the extent that customers enter into contracts with CSPs or LSEs to manage their payments, M&V can be negotiated as part of a bilateral commercial contract between a customer and its CSP or LSE.

This approach provides more flexibility to customers to limit usage at their discretion. There is no requirement to be available year round or every hour of every day. There is no 30 minute notice requirement. There is no requirement to offer energy into the day-ahead market. All decisions about interrupting are up to the customers only and they may enter into bilateral commercial arrangements with CSPs at their sole discretion. Customers would pay for capacity and energy depending solely on metered load.

A transition to this end state should be defined in order to ensure that appropriate levels of demand side response are incorporated in PJM's load forecasts and thus in the demand curve in the capacity market for the next three years. That transition should be defined by the PRD rules, modified as proposed by the MMU.

This approach would work under the CP design in the capacity market. This approach is entirely consistent with the Supreme Court decision in *EPSA* as it does not depend on whether FERC has jurisdiction over the demand side. This approach will allow FERC to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets. The decision of the Supreme Court addressed jurisdictional issues and did not address the merits of FERC's approach. The Supreme Court's decision has removed the uncertainty surrounding the jurisdictional issues and created the opportunity for FERC to revisit its approach to demand side.

108 See the MMU package within the *SODRSTF Matrix*, <http://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180802/20180802-item-04-sodrstf-matrix.ashx>.
109 *Summer-Only Demand Response Senior Task Force*, PJM, <http://www.pjm.com/committees-and-groups/task-forces/sodrstf.aspx>, (Accessed August 3, 2018).

Overview: Section 7, Net Revenue

Net Revenue

- Energy net revenues are significantly affected by energy prices and fuel prices. Energy prices and fuel prices were both higher and more volatile in the first nine months of 2018 than in the first nine months of 2017. The result was higher margins for all unit types.
- In the first nine months of 2018, average energy market net revenues increased by 70 percent for a new CT, 39 percent for a new CC, 202 percent for a new coal plant (CP), 37 percent for a new nuclear plant (NP), 461 percent for a new diesel (DS), 22 percent for a new wind installation, and 10 percent for a new solar installation compared to the first nine months of 2017.
- The relative prices of fuel varied during the first nine months of 2018. The marginal cost of the new CC and CT was above that of the new CP during periods of high gas costs in January.
- Based on forward prices for energy, known forward prices for capacity, and public data on costs, there are three nuclear plants in PJM at risk of not covering their annual avoidable costs on average over the next three years (2019 through 2021). The three plants are Davis Besse, Perry, and Three Mile Island. All three plants are single unit sites which have higher operating costs per MWh than multiple unit plants. The three plants together are 2,939 MW, all of which have requested deactivation.

Historical New Entrant CT and CC Revenue Adequacy

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis through September 2018, although a new CC in the BGE Zone was very close. The analysis also shows that theoretical new entrant CTs and CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of capacity market revenue in covering total costs.

Section 7 Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs.

Unlike cost of service regulation, markets do not guarantee that units will cover their costs. New CT and CC units that began operation in 2007 have not covered their total costs from energy market and capacity market revenues through September 2018 in the ComEd Zone and in the PSEG Zone and were very close in the BGE Zone. New CT and CC units that began operation on June 1, 2012, have covered or more than covered their total costs in the PSEG Zone and the BGE Zone through September 2018, and have not covered their total costs in the ComEd Zone.

Overview: Section 8, Environmental and Renewables

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[110] All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.
- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine particulate matter (PM) and ozone national ambient air quality standards (NAAQS). The CAA also requires that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[111]
- **National Emission Standards for Reciprocating Internal Combustion Engines.** The national emissions standards uniformly apply to all RICE.[112] All RICE are allowed to operate during emergencies, including declared Energy Emergency Alert Level 2 or five percent voltage/frequency deviations.[113]
- **Greenhouse Gas Emissions Rule.** On August 3, 2015, the EPA issued a final rule for regulating CO_2 from certain existing power generation facilities titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (the Clean Power Plan).[114] On February 9, 2016, the U.S. Supreme Court issued a stay of the rule that will prevent its taking effect until judicial review is completed.[115] On October 10, 2017, the EPA proposed to repeal the Clean Power Plan based a determination that the Plan exceeds the EPA's authority under Section 111 of the EPAs Act.[116]
- **Cooling Water Intakes.** An EPA rule implementing Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.[117]

State Environmental Regulation

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 emissions cap and trade agreement among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont that applies to power generation facilities. The auction price in the September 9, 2018, auction for the 2015/2018 compliance period was $4.50 per ton. The clearing price is equivalent to a price of $4.96 per metric tonne, the unit used in other carbon markets. The price increased by $0.48 per ton, 11.9 percent, from $4.02 per ton from June 13, 2018, to $4.50 per ton for September 9, 2018.
- **Carbon Price.** If the price of carbon were $50.00 per metric tonne, the short run marginal costs would increase by $25.04 per MWh for a new combustion turbine (CT) unit, $17.72 per MWh for a new combined cycle (CC) unit and $43.15 per MWh for a new coal plant (CP).

State Renewable Portfolio Standards

Many states in PJM have enacted legislation to require that a defined percentage of retail suppliers' load be served by renewable resources, for which definitions vary. These are typically known as renewable portfolio standards, or RPS. As of September 30, 2018, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC had renewable portfolio standards. Virginia and Indiana had voluntary renewable

110 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).

111 CAA § 110(a)(2)(D)(i)(I).

112 EPA, Memorandum, Peter Tsirigotis Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines (April 15, 2016).

113 See 40 CFR §§ 60.4211(f)(2)(ii)–(iii), 60.4243(d)(2)(ii)–(iii), and 63.6640(f)(2)(ii)–(iii) (Declared Energy Emergency Alert Level 2 or 5 percent voltage/frequency deviations); 0 CFR §§ 60.4211(f)(1), 60.4243(d)(1), and 63.6640(f)(1) ("There is no time limit on the use of emergency stationary ICE in emergency situations."); 40 §§ CFR 60.4211(f)(3), 60.4243(d)(3), 63.6640(f)(3)–(4).

114 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule *mimeo* (August 3, 2015), also known as the "Clean Power Plan."

115 North Dakota v. EPA, et al., Order 15A793.

116 *See Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2017-0355, 82 Fed. Reg. 48035 (October 16, 2017).

117 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (Aug. 15, 2014).

portfolio standards. Kentucky and Tennessee did not have renewable portfolio standards.

Emissions Controls in PJM Markets

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. As of September 30 2018, 93.1 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 emissions, while 99.5 percent of coal steam MW had some type of particulate control, and 93.9 percent of fossil fuel fired capacity in PJM had NO_X emission control technology.

Renewable Generation

Total wind and solar generation was 2.6 percent of total generation in PJM for the first nine months of 2018. Tier I generation was 4.2 percent of total generation in PJM and Tier II generation was 2.8 percent of total generation in PJM for the first nine months of 2018.

Section 8 Recommendations

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the data more transparent. (Priority: Low. First reported Q2, 2018. Status: Not adopted.)

Section 8 Conclusion

Environmental requirements and renewable energy mandates at both the federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. Renewable energy credit (REC) markets are markets related to the production and purchase of wholesale power, but FERC has determined that RECs are not regulated under the Federal Power Act unless the REC is sold as part of a transaction that also includes a wholesale sale of electric energy in a bundled transaction.[118]

RECs provide out of market payments to qualifying renewable resources, primarily wind and solar. The credits provide an incentive to make negative energy offers and more generally provide an incentive to enter the market, to remain in the market and to operate whenever possible. These subsidies affect the offer behavior and the operational behavior of these resources in PJM markets and in some cases the existence of these resources and thus the market prices and the mix of clearing resources.

RECs clearly affect prices in the PJM wholesale power market. Some resources are not economic except for the ability to purchase or sell RECs. REC markets are not transparent. Data on REC prices, clearing quantities and markets are not publicly available for all PJM states. RECs do not need to be consumed during the year of production which creates multiple prices for a REC based on the year of origination. RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. It would be preferable to have a single, transparent market for RECs operated by the PJM RTO that would meet the standards and requirements of all states in the PJM footprint including those with no RPS. This would provide better information for market participants about supply and demand and prices and contribute to a more efficient and competitive market and to better price formation. This could also facilitate entry by qualifying renewable resources by reducing the risks associated with lack of transparent market data.

118 See 139 FERC ¶ 61,061 at PP 18, 22 (2012) ("[W]e conclude that unbundled REC transactions fall outside of the Commission's jurisdiction under sections 201, 205 and 206 of the FPA. We further conclude that bundled REC transactions fall within the Commission's jurisdiction under sections 201, 205 and 206 of the FPA,… [A]lthough a transaction may not directly involve the transmission or sale of electric energy, the transaction could still fall under the Commission's jurisdiction because it is 'in connection with' or 'affects' jurisdictional rates or charges.").

The economic logic of RPS programs and the associated REC and SREC prices is not clear. The price of carbon implied by REC prices ranges from $4.70 per tonne in Washington, D.C. to $35.41 per tonne in Pennsylvania. The price of carbon implied by SREC prices ranges from $17.76 per tonne in Pennsylvania to $839.29 per tonne in Washington, D.C. The effective prices for carbon compare to the 2018 average RGGI clearing price of $4.52 per tonne and to the social cost of carbon which is estimated in the range of $40 per tonne.[119] The impact on the cost of generation from a new combined cycle unit of an $800 per tonne carbon price would be $283.56 per MWh. The impact of a $40 per tonne carbon price would be $14.18 per MWh. This wide range of implied carbon prices is not consistent with an efficient, competitive, least cost approach to the reduction of emissions.

PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. Costs for environmental controls are part of bids for capacity resources in the PJM Capacity Market. The costs of emissions credits are included in energy offers. PJM markets also provide a flexible mechanism that incorporates renewable resources and the impacts of renewable energy credit markets, and ensure that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

PJM markets could also provide a flexible mechanism to limit carbon output, for example by incorporating a consistent carbon price in unit offers which would be reflected in PJM's economic dispatch. If there is a social decision to limit carbon output, a consistent carbon price would be the most efficient way to implement that decision. It would also be an alternative to specific subsidies to individual nuclear power plants and to the current wide range of implied carbon prices embedded in RPS programs and instead provide a market signal to which any resource could respond. The imposition of specific and prescriptive environmental dispatch rules would, in contrast, pose a threat to economic dispatch and efficient markets and create very difficult market power monitoring and mitigation issues. The provision of subsidies to individual units creates a discriminatory regime that is not consistent with competition. The use of inconsistent implied carbon prices by state is also inconsistent with an efficient market and inconsistent with the least cost approach to meeting state environmental goals.

Overview: Section 9, Interchange Transactions

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2018, PJM was a monthly net importer of energy in the Real-Time Energy Market in March and April, and a net exporter of energy in the remaining months.[120] In the first nine months of 2018, the real-time net interchange of -12,205.8 GWh was higher than the net interchange of -17,891.2 GWh in the first nine months of 2017.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2018, PJM was a monthly net importer of energy in the Day-Ahead Energy Market in March, April, May, June, July and August, and a net exporter of energy in the remaining months. In the first nine months of 2018, the total day-ahead net interchange of 1,810.5 GWh was higher than net interchange of -14,655.8 GWh in the first nine months of 2017.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first nine months of 2018, gross imports in the Day-Ahead Energy Market were 260.8 percent of gross imports in the Real-Time Energy Market (177.8 percent in the first nine months of 2017). In the first nine months of 2018, gross exports in the Day-Ahead Energy Market were 128.8 percent of the gross exports in the Real-Time Energy Market (122.2 percent in the first nine months of 2017).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2018, there were net scheduled exports at ten of PJM's 20 interfaces in the Real-Time Energy Market.

119 "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12899", Interagency Working Group on the Social Cost of Greenhouse Gases, United States Government, (August 2016), <https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf>.

120 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2018, there were net scheduled exports at 12 of PJM's 18 interface pricing points eligible for real-time transactions in the Real-Time Energy Market.[121]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2018, there were net scheduled exports at 12 of PJM's 20 interfaces in the Day-Ahead Energy Market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2018, there were net scheduled exports at eight of PJM's 19 interface pricing points eligible for day-ahead transactions in the Day-Ahead Energy Market.
- **Up to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2018, up to congestion transactions were net exports at four of PJM's 19 interface pricing points eligible for day-ahead transactions in the Day-Ahead Energy Market.
- **Inadvertent Interchange.** In the first nine months of 2018, net scheduled interchange was 12,206 GWh and net actual interchange was 12,197 GWh, a difference of 8 GWh. In the first nine months of 2017, the difference was 151 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In the first nine months of 2018, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with 4 GWh of net scheduled interchange and -6,492 GWh of net actual interchange, a difference of 6,496 GWh. In the first nine months of 2018, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 8,289 GWh of net scheduled interchange and 21,981 GWh of net actual interchange, a difference of 13,692 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first nine months of 2018, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface in 56.1 percent of the hours.
- **PJM and New York ISO Interface Prices.** In the first nine months of 2018, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/NYIS Interface and the NYISO/PJM proxy bus in 52.8 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first nine months of 2018, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Neptune Interface and the NYISO Neptune bus in 63.0 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first nine months of 2018, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Linden Interface and the NYISO Linden bus in 59.2 percent of the hours.
- **Hudson DC Line.** In the first nine months of 2018, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Hudson Interface and the NYISO Hudson bus in 56.3 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued four TLRs of level 3a or higher in the first nine months of 2018, compared to three such TLRs issued in the first nine months of 2017.
- **Up to congestion.** On February 20, 2018, FERC issued an Order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces.[122] As a result, market participants reduced up to congestion trading effective February 22, 2018. The average number of up to congestion bids submitted in the Day-Ahead Energy

121 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).

122 162 FERC ¶ 61,139 (2018).

Market decreased by 53.2 percent, from 146,930 bids per day in the first nine months of 2017 to 68,693 bids per day in the first nine months of 2018. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market decreased by 51.6 percent, from 875,065 MWh per day in the first nine months of 2017, to 423,268 MWh per day in the first nine months of 2018.

- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule in response to FERC Order No. 764.[123] [124] PJM and the MMU issued a statement indicating ongoing concern about market participants' scheduling behavior, and a commitment to address any scheduling behavior that raises operational or market manipulation concerns.[125]

Section 9 Recommendations

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point-to-point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)

123 Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).
124 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).
125 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, at: <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.

- The MMU recommends that PJM immediately provide the required 12-month notice to Duke Energy Progress (DEP) to unilaterally terminate the Joint Operating Agreement. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJMSettlement Inc. immediately request a credit evaluation from all companies that engaged in up to congestion transactions between September 8, 2014, and December 31, 2015. If PJM has the authority, PJM should ensure that the potential exposure to uplift for that period be included as a contingency in the companies' calculations for credit levels and/or collateral requirements. If PJM does not have the authority to take such steps, PJM should request guidance from FERC. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Partially adopted, 2015.)
- The MMU recommends that PJM and MISO work together to align interface pricing definitions, using the same number of external buses and selecting buses in close proximity on either side of the border with comparable bus weights. (Priority: Medium. First reported 2012. Status: Adopted 2017.)

Section 9 Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed nonmarket areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and nonmarket areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial congestion offsets (FTRs and ARRs in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Nonmarket areas do not include these features. The market areas are extremely transparent and the nonmarket areas are not transparent.

The MMU's recommendations related to transactions with external balancing authorities all share the goal of improving the economic efficiency of interchange transactions. The standard of comparison is an LMP market. In an LMP market, redispatch based on LMP and competitive generator offers results in an efficient dispatch and efficient prices. The goal of designing interface transaction rules should be to match the outcomes that would exist in an LMP market.

Overview: Section 10, Ancillary Services

Primary Reserve

PJM's primary reserves are made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 minutes. Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement.[126]

On April 1, 2018, PJM implemented five minute settlements. PJM determines the primary reserve requirement based on the most severe single contingency every five minutes. The market solution calculates the available tier 1 synchronized reserve every five minutes. In every five minute interval, the required synchronized reserve and nonsynchronized reserve are calculated and dispatched, and there are associated clearing prices (SRMCP and NSRMCP).

126 See PJM. "Manual 10: Pre-Scheduling Operations," Rev. 36 (Dec. 22, 2017), p. 24.

Scheduled resources are credited based on their five minute assignment and clearing price.

Market Structure

- **Supply.** Primary reserve is satisfied by both synchronized reserve (generation or demand response currently synchronized to the grid and available within 10 minutes), and nonsynchronized reserve (generation currently off-line but available to start and provide energy within 10 minutes).
- **Demand.** The PJM primary reserve requirement is 150 percent of the most severe single contingency. In the first nine months of 2018, the average primary reserve requirement was 2,248.3 MW in the RTO Zone and 2,226.7 MW in the MAD Subzone.

Tier 1 Synchronized Reserve

Synchronized reserve is provided by generators or demand response resources synchronized to the grid and capable of increasing output or decreasing load within 10 minutes. Synchronized reserve consists of tier 1 and tier 2 synchronized reserves.

Tier 1 synchronized reserve is the capability of online resources following economic dispatch to ramp up in 10 minutes from their current output in response to a synchronized reserve event. There is no formal market for tier 1 synchronized reserve.

- **Supply.** No offers are made for tier 1 synchronized reserves. The market solution estimates tier 1 synchronized reserve as available 10 minute ramp from the energy dispatch. In the first nine months of 2018, there was an average hourly supply of 1,576.6 MW of tier 1 available in the RTO Zone. In the first nine months of 2018, there was an average hourly supply of 660.8 MW of tier 1 synchronized reserve available within the MAD Subzone and an additional 789.6 MW of tier 1 available to the MAD Subzone from the RTO Zone.
- **Demand.** The synchronized reserve requirement is calculated for each five minute interval as the most severe single contingency within both the RTO Zone and the MAD Subzone. The requirement can be met with tier 1 or tier 2 synchronized reserves.
- **Tier 1 Synchronized Reserve Event Response.** Tier 1 synchronized reserve is paid when a synchronized reserve event occurs and it responds. When a synchronized reserve event is called, all tier 1 response is paid the average of five minute LMPs during the event plus $50 per MW. This is the Synchronized Energy Premium Price.

  Of the Degree of Generator Performance (DGP) adjusted tier 1 synchronized reserve MW estimated at market clearing, 62.6 percent actually responded during the six synchronized reserve events with a duration of 10 minutes or longer in the first nine months of 2018.
- **Issues.** The competitive offer for tier 1 synchronized reserves is zero, as there is no incremental cost associated with the ability to ramp up from the current economic dispatch point and the appropriate payment for responding to an event is the five-minute LMP plus $50 per MWh. The tariff requires payment of the tier 2 synchronized reserve market clearing price to tier 1 resources whenever the nonsynchronized reserve market clearing price rises above zero. This requirement is unnecessary and inconsistent with efficient markets. This change had a significant impact on the cost of tier 1 synchronized reserves, resulting in a windfall payment of $89,719,045 to tier 1 resources in 2014, $34,397,441 in 2015, $4,948,084 in 2016, $2,197,514 in 2017, and $3,330,981 in the first nine months of 2018.

Tier 2 Synchronized Reserve Market

Tier 2 synchronized reserve is part of primary reserve and is comprised of resources that are synchronized to the grid, that incur costs to be synchronized, that have an obligation to respond, that have penalties for failure to respond, and that must be dispatched in order to satisfy the synchronized reserve requirement.

When the synchronized reserve requirement cannot be met with tier 1 synchronized reserve, PJM uses a market to satisfy the balance of the requirement with tier 2 synchronized reserve. The Tier 2 Synchronized Reserve Market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve Subzone (MAD).

Market Structure

- **Supply.** In the first nine months of 2018, the supply of offered and eligible tier 2 synchronized reserve was 24,831.9 MW in the RTO Zone of which 6,921.2 MW was located in the MAD Subzone. 2,474.0 MW of DSR was available in the RTO Zone.
- **Demand.** The average hourly synchronized reserve requirement was 1,562.3 MW in the RTO Reserve Zone and 1,547.9 MW for the Mid-Atlantic Dominion Reserve Subzone. The hourly average required tier 2 synchronized reserve was 291.7 MW in the MAD Subzone and 515.6 MW in the RTO.
- **Market Concentration.** Both the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market and the RTO Synchronized Reserve Zone Market were characterized by structural market power in the first nine months of 2018.

  In the first nine months of 2018, the average HHI for tier 2 synchronized reserve in the RTO Zone was 5411 which is classified as highly concentrated. The MMU calculates that 14.4 percent of hours would have failed a three pivotal supplier test.

Market Conduct

- **Offers.** There is a must offer requirement for tier 2 synchronized reserve. All nonemergency generation capacity resources are required to submit a daily offer for tier 2 synchronized reserve, unless the unit type is exempt. Tier 2 synchronized reserve offers from generating units are subject to an offer cap of marginal cost plus $7.50 per MW, plus opportunity cost which is calculated by PJM. PJM automatically enters an offer of $0 for tier 2 synchronized reserve when an offer is not entered by the owner.

Market Performance

- **Price.** The weighted average price for tier 2 synchronized reserve for all cleared hours/intervals in the Mid-Atlantic Dominion (MAD) Subzone was $4.92 per MW in the first nine months of 2018, an increase of $1.58 from the first nine months of 2017.

  The weighted average price for tier 2 synchronized reserve for all cleared hours/intervals in the RTO Synchronized Reserve Zone was $5.78 per MW in the first nine months of 2018, an increase of $2.34 from the first nine months of 2017.

Nonsynchronized Reserve Market

Nonsynchronized reserve is part of primary reserve and includes the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone (MAD). Nonsynchronized reserve is comprised of nonemergency energy resources not currently synchronized to the grid that can provide energy within 10 minutes. Nonsynchronized reserve is available to fill the primary reserve requirement above the synchronized reserve requirement. Generation owners do not submit supply offers for nonsynchronized reserve. PJM defines the demand curve for nonsynchronized reserve and PJM defines the supply curve based on nonemergency generation resources that are available to provide energy and can start in 10 minutes or less (based on offer parameters), and on the resource opportunity costs calculated by PJM.

Market Structure

- **Supply.** In the first nine months of 2018, the average hourly supply of eligible nonsynchronized reserve was 2,598.8 MW in the RTO Zone.
- **Demand.** Demand for nonsynchronized reserve equals the primary reserve requirement minus the tier 1 synchronized reserve estimate and minus the scheduled tier 2 synchronized reserve.[127] In the RTO Zone, the market scheduled an hourly average of 1,188.8 MW of nonsynchronized reserve in the first nine months of 2018.

127 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 98 (October 25, 2018), p. 81. "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves. "

- **Market Concentration.** In the first nine months of 2018, the weighted average HHI for cleared nonsynchronized reserve in the RTO Zone was 4459, which is highly concentrated. The MMU calculates that the three pivotal supplier test would have failed in 94.3 percent of hours.

Market Conduct

- **Offers.** Generation owners do not submit supply offers. Nonemergency generation resources that are available to provide energy and can start in 10 minutes or less are considered available for nonsynchronized reserves by the market solution software. PJM calculates the associated offer prices based on PJM calculations of resource specific opportunity costs.

Market Performance

- **Price.** The nonsynchronized reserve price is determined by the opportunity cost of the marginal nonsynchronized reserve unit. The nonsynchronized reserve weighted average price for all hours in the RTO Reserve Zone was $0.18 per MW in the first nine months of 2018. The price cleared above $0.00 in 1.8 percent of hours.

Secondary Reserve

There is no NERC standard for secondary reserve. PJM defines secondary reserve as reserves (online or offline available for dispatch) that can be converted to energy in 30 minutes. PJM defines a secondary reserve requirement but does not have a goal to maintain this reserve requirement in real time.

PJM maintains a day-ahead, offer-based market for 30 minute day-ahead secondary reserve. The Day-Ahead Scheduling Reserve Market (DASR) has no performance obligations except that a unit which clears the DASR market may not be on an outage in real time.[128] If DASR units are on an outage in real time or cleared DASR MW are not available, the DASR payment is not made.

Market Structure

- **Supply.** The DASR Market is a must offer market. Any resources that do not make an offer have their offer set to $0.00 per MW. DASR is calculated by the day-ahead market solution as the lesser of the 30 minute energy ramp rate or the economic maximum MW minus the day-ahead dispatch point for all online units. In the first nine months of 2018, the average available hourly DASR was 39,132.7 MW.
- **Demand.** The DASR requirement for 2018 is 5.28 percent of peak load forecast, down from 5.52 percent in 2017. The average DASR MW purchased from the first nine months of 2018 was 5,625.4 MW per hour, compared to 4,608.8 MW per hour in 2017.
- **Concentration.** In the first nine months of 2018, the MMU calculates that the DASR Market would have failed the three pivotal supplier test in 13.4 percent of hours.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. PJM calculates the opportunity cost for each resource. All offers by resource owners greater than zero constitute economic withholding. In the first nine months of 2018, a daily average of 38.8 percent of units offered above $0.00. A daily average of 15.7 percent of units offered above $5.
- **DR.** Demand resources are eligible to participate in the DASR Market. Some demand resources have entered offers for DASR. No demand resources cleared the DASR market in 2018.

Market Performance

- **Price.** In the first nine months of 2018, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $2.36.

128 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Rev. 98 (October 25, 2018), p. 155 §11.2.7.

Regulation Market

The PJM Regulation Market is a real-time market. Regulation is provided by generation resources and demand response resources that qualify to follow one of two regulation signals, RegA or RegD. PJM jointly optimizes regulation with synchronized reserve and energy to provide all three products at least cost. The PJM regulation market design includes three clearing price components: capability; performance; and opportunity cost. The RegA signal is designed for energy unlimited resources with physically constrained ramp ability. The RegD signal is designed for energy limited resources with fast ramp rates. In the Regulation Market RegD MW are converted to effective MW using a marginal rate of substitution (MRTS), called a marginal benefit function (MBF). Correctly implemented, the MBF would be the marginal rate of technical substitution (MRTS) between RegA and RegD, holding the level of regulation service constant. The current market design is critically flawed as it has not properly implemented the MBF as an MRTS between RegA and RegD resource MW and the MBF has not been consistently applied in the optimization, clearing and settlement of the Regulation Market.

Market Structure

- **Supply.** In the first nine months of 2018, the average hourly eligible supply of regulation for nonramp hours was 1,099.3 performance adjusted MW (857.7 effective MW). This was a decrease of 36.2 performance adjusted MW (a decrease of 1.3 effective MW) from the first nine months of 2017, when the average hourly eligible supply of regulation was 1,135.6 performance adjusted MW (858.9 effective MW). In the first nine months of 2018, the average hourly eligible supply of regulation for ramp hours was 1,411.1 performance adjusted MW (1,191.8 effective MW). This was a decrease of 11.9 performance adjusted MW (an increase of 18.1 effective MW) from the first nine months of 2017, when the average hourly eligible supply of regulation was 1,423.0 performance adjusted MW (1,173.7 effective MW).

- **Demand.** Prior to January 9, 2017, the hourly regulation demand was set to 525.0 effective MW for nonramp hours and 700.0 effective MW for ramp hours. Starting January 9, 2017, the hourly regulation demand was set to 525.0 effective MW for nonramp hours and 800.0 effective MW for ramp hours.

- **Supply and Demand.** The nonramp regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources equal to 486.8 hourly average performance adjusted actual MW in the first nine months of 2018. This is a decrease of 4.8 performance adjusted actual MW from the first nine months of 2017, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 491.6 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of RegA and RegD resources equal to 750.0 hourly average performance adjusted actual MW in the first nine months of 2018. This is an increase of 31.2 performance adjusted actual MW from the first nine months of 2017, where the average hourly regulation cleared MW for ramp hours were 718.8 performance adjusted actual MW.

  The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.88 in the first nine months of 2018. This is a decrease of 5.1 percent from the first nine months of 2017, when the ratio was 1.98. The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 2.26 in the first nine months of 2018. This is a decrease of 2.1 percent from the first nine months of 2017, when the ratio was 2.31.

- **Market Concentration.** In the first nine months of 2018, the effective MW weighted average HHI of RegA resources was 2477 which is highly concentrated and the weighted average HHI of RegD resources was 1537 which is also highly concentrated.[129] The weighted average HHI of all resources was 1135, which is moderately concentrated. In the first nine months of 2018, the three pivotal supplier test was failed in 82.8 percent of hours.

129 HHI results are based on market shares of effective MW, defined as regulation capability MW adjusted by performance score and resource specific benefit factor, consistent with the way the regulation market is cleared.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost-based offer and may submit a price-based offer. Offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or RegD.[130] In the first nine months of 2018, there were 225 resources following the RegA signal and 65 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $28.23 per MW of regulation in the first nine months of 2018. This is an increase of $12.53 per MW, or 79.8 percent, from the weighted average clearing price of $15.70 per MW in the first nine months of 2017. The weighted average cost of regulation in the first nine months of 2018 was $35.05 per MW of regulation. This is an increase of $13.35 per MW, or 61.5 percent, from the weighted average cost of $21.70 per MW in the first nine months of 2017.

- **Prices.** RegD resources continue to be incorrectly compensated relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment and settlement processes. If the Regulation Market were functioning efficiently, RegD and RegA resources would be paid the same price per effective MW. RegA resources are paid on the basis of dollars per effective MW of RegA. RegD resources are not paid in terms of dollars per effective MW of RegA because the marginal benefit factor is not used in settlements. When the marginal benefit factor is above 1.0, RegD resources are generally (depending on the mileage ratio) underpaid on a per effective MW basis. When the MBF is less than one, RegD resources are generally overpaid on a per effective MW basis.

- **Marginal Benefit Factor Function.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor function is incorrectly defined and applied in the PJM market clearing. Correctly defined, the MBF function represents the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. Correctly implemented, the MBF would be consistently applied in the Regulation Market clearing and settlement. The current incorrect and inconsistent implementation of the MBF function has resulted in the PJM Regulation Market over procuring RegD relative to RegA in most hours and in a consistently inefficient market signal to participants regarding the value of RegD to the market in every hour. This over procurement of RegD can also degrade the ability of PJM to control ACE.

- **Changes to the Regulation Market.** The MMU and PJM developed a joint proposal to address the significant flaws in the regulation market design which was approved by the PJM Members Committee on July 27, 2017, and filed with the FERC on October 17, 2017. The proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market. On March 30, 2018, this joint proposal was rejected by the FERC.[131] The MMU and PJM have filed requests for rehearing.[132]

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[133]

In the first nine months of 2018, total black start charges were $49.4 million, including $49.3 million in revenue requirement charges and $0.139 million in operating reserve charges. Black start revenue requirements consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor. Black start operating reserve charges are paid to units scheduled in the Day-Ahead Energy Market or committed in real time to provide black start service under the ALR option or for black start

130 See the *2017 State of the Market Report for PJM*, Vol. 2, Appendix F "Ancillary Services Markets."

131 162 FERC ¶ 61,295.

132 FERC Docket No. ER18-87-002.

133 OATT Schedule 1 § 1.3BB.

testing. Black start zonal charges for the first nine months of 2018 ranged from $0.05 per MW-day in the DLCO Zone (total charges were $36,936) to $4.30 per MW-day in the PENELEC Zone (total charges were $3,391,667).

Reactive

Reactive service, reactive supply and voltage control are provided by generation and other sources of reactive power (measured in MVAr). Reactive power helps maintain appropriate voltage levels on the transmission system and is essential to the flow of real power (measured in MW).

Reactive capability revenue requirements are based on FERC approved filings that permit recovery based on a cost of service approach.[134] Reactive service charges are paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing reactive service. Reactive service charges are paid for scheduling in the Day-Ahead Energy Market and committing units in real time that provide reactive service. In the first nine months of 2018, total reactive charges were $259.6 million, a 5.9 percent increase from $245.2 million in the first nine months of 2017. Reactive capability revenue requirement charges increased from $231.1 million in the first nine months of 2017 to $247.1 million in the first nine months of 2018 and reactive service charges increased from $14.0 million in the first nine months of 2017 to $12.4 million in the first nine months of 2018. Total reactive service charges in the first nine months of 2018 ranged from $0 in the RECO Zone, which has no generating units, to $39.9 million in the ComEd Zone.

Frequency Response

In response to a November 17, 2016 FERC NOPR, PJM formed the Primary Frequency Response Senior Task Force (PFRSTF) to review primary frequency response and propose changes to its tariff and operating manuals, including consideration of compensation mechanisms if needed.[135]

134 OATT Schedule 2.
135 157 FERC ¶ 61,122 (2016).

Section 10 Recommendations

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. FERC rejected, pending rehearing request before FERC.)
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Not adopted. FERC rejected, pending rehearing request before FERC.)
- The MMU recommends that the lost opportunity cost calculation used in the Regulation Market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected, pending rehearing request before FERC.)
- The MMU recommends that, to prevent gaming, there be a penalty enforced in the Regulation Market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour. (Priority: Medium. First reported 2016. Status: Not adopted. FERC rejected, pending rehearing request before FERC.)
- The MMU recommends enhanced documentation of the implementation of the Regulation Market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected, pending rehearing request before FERC.)
- The MMU recommends that all data necessary to perform the Regulation Market three pivotal supplier test be saved so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Adopted, 2018.)
- The MMU recommends the use of a single five minute clearing price based on actual five minute LMP and lost opportunity cost to improve the

performance of the Regulation Market. (Priority: Medium. First reported 2010. Status: Adopted in 2012.)

- The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the Regulation Market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the $7.50 margin be eliminated from the definition of the cost of tier 2 synchronized reserve because it is a markup and not a cost. (Priority: Medium. New Recommendation. Status: Not adopted.)
- The MMU recommends that the rule requiring that tier 1 synchronized reserve resources are paid the tier 2 price when the nonsynchronized reserve price is above zero be eliminated immediately and that, under the current rule, tier 1 synchronized reserve resources not be paid the tier 2 price when they do not respond. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced on a daily and hourly basis. The MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer MW to 0 MW. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM be more explicit and transparent about why tier 1 biasing is used in defining demand in the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for estimating tier 1 MW, define rules for the use and amount of tier 1 biasing and identify the rule based reasons for each instance of biasing. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual five minute LMP and actual LOC and not the forecast LMP. (Priority: Low. First reported 2010. Status: Adopted, 2016.)
- The MMU recommends that no payments be made to tier 1 synchronized reserve resources if they are deselected in the PJM market solution. The MMU also recommends that documentation of the tier 1 synchronized reserve deselection process be published. (Priority: High. First reported 2014. Status: Adopted, 2014.)
- The MMU recommends that, for calculating the penalty for a tier 2 resource failing to meet its scheduled obligation during a spinning event, the definition of the IPI be changed from the average number of days between events to the actual number of days since the last event greater than 10 minutes. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that offers in the DASR Market be based on opportunity cost only in order to eliminate market power. (Priority: Low. First reported 2009. Modified 2018. Status: Not adopted.)
- The MMU recommends that separate cost of service payments for reactive capability be eliminated and the cost of reactive capability be recovered in the capacity market. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that payments for reactive capability, if continued, be based on the 0.90 power factor that PJM has determined is necessary. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends for oil tanks shared with other resources that only a proportionate share of the minimum tank suction level (MTSL) be

allocated to black start service. The MMU further recommends that the PJM tariff be updated to clearly state how the MTSL will be calculated for black start units sharing oil tanks. (Priority: Medium. First reported 2017. Status: Not adopted.)

- The MMU recommends that capability to operate under the proposed deadband (+/- 0.036 HZ) and droop (5 percent) settings in order to provide frequency control be mandated as a condition of interconnection and that such capability be required of both new and existing resources. The MMU recommends that no additional compensation be provided as the current PJM market design provides adequate compensation. (Priority: Low. First reported 2017. Status: Not adopted.)

Section 10 Conclusion

The current PJM regulation market design that incorporates two signals using two resource types was a result of FERC Order No. 755 and subsequent orders.[136]

The design of the PJM Regulation Market is significantly flawed. The market design does not correctly incorporate the marginal rate of technical substitution (MRTS) in market clearing and settlement. The market design uses the marginal benefit factor (MBF) to incorrectly represent the MRTS and uses a mileage ratio instead of the MBF in settlement. This failure to correctly and consistently incorporate the MRTS into the regulation market design has resulted in both underpayment and overpayment of RegD resources and in the over procurement of RegD resources in all hours. The market results continue to include the incorrect definition of opportunity cost. These issues are the basis for the MMU's conclusion that the regulation market design is flawed.

To address these flaws, the MMU and PJM developed a joint proposal which was approved by the PJM Members Committee on July 27, 2017, and filed with FERC on October 17, 2017.[137] The PJM/MMU joint proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market. The FERC rejected the joint proposal on March 30, 2018 as being noncompliant with Order No. 755.[138] The MMU and PJM have separately filed requests for rehearing.[139]

The structure of the Tier 2 Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. As a result, these markets are operated with market clearing prices and with offers based on the marginal cost of producing the product plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. However, the $7.50 margin is not a cost. The margin is effectively a rule-based form of market power and is therefore not consistent with a competitive outcome. The $7.50 margin should be eliminated. Participant performance has not been adequate. Compliance with calls to respond to actual synchronized reserve events remains less than 100 percent. For the six spinning events 10 minutes or longer in 2016, the average tier 2 synchronized reserve response was 85.5 percent of all scheduled MW. For the six spinning events 10 minutes or longer in 2017, the response was 87.6 percent of scheduled tier 2 MW. For the six spinning events longer than 10 minutes in the first nine months of 2018, the response was 75.3 percent of scheduled tier 2 MW. Actual participant performance implies that the penalty structure is not adequate to incent performance.

The rule that requires payment of the tier 2 synchronized reserve price to tier 1 synchronized reserve resources when the nonsynchronized reserve price is greater than zero, is inefficient and results in a substantial windfall payment to the holders of tier 1 synchronized reserve resources. Tier 1 resources have no obligation to perform and pay no penalties if they do not perform, and tier 1 resources do not incur any costs when they are part of the tier 1 estimate in the market solution. Tier 1 resources are already paid for their response if they do respond. Tier 1 resources require no additional payment. If tier 1 resources wish to be paid as tier 2 resources, the rules provide the opportunity to make competitive offers in the tier 2 market and take on the associated obligations.

136 Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).
137 18 CFR § 385,211 (2017)
138 162 FERC ¶ 61,295 (2018).
139 The MMU filed its request for rehearing on April 27, 2018, and PJM filed its request for rehearing on April 30, 2018.

Overpayment of tier 1 resources based on this rule added $89.7 million to the cost of primary reserve in 2014, $34.1 million in 2015, $4.9 million in 2016, $2.2 million in 2017, and $3.3 million in the first nine months of 2018.

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

The MMU concludes that the regulation market results were competitive, although the market design is flawed. The MMU concludes that the synchronized reserve market results were competitive, although the $7.50 margin should be removed. The MMU concludes that the DASR market results were competitive, although offers above the competitive level continue to affect prices.

Overview: Section 11, Congestion and Marginal Losses

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $660.8 million or 145.1 percent, from $455.4 million in the first nine months of 2017 to $1,116.2 million in the first nine months of 2018.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $669.2 million or 138.7 percent, from $482.5 million in the first nine months of 2017 to $1,151.7 million in the first nine months of 2018.
- **Balancing Congestion.** Negative balancing congestion costs increased by $8.4 million or 30.8 percent, from -$27.1 million in the first nine months of 2017 to -$35.5 million in the first nine months of 2018. Negative balancing explicit costs decreased by $3.1 million or 46.3 percent, from -$6.7 million in the first nine months of 2017 to -$3.6 million in the first nine months of 2018.
- **Real-Time Congestion.** Real-time congestion costs increased by $729.1 million or 136.6 percent, from $533.8 million in the first nine months of 2017 to $1,262.9 million in the first nine months of 2018.
- **Monthly Congestion.** Monthly total congestion costs in the first nine months of 2018 ranged from $45.2 million in February to $535.9 million in January.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the AEP - DOM Interface, the Cloverdale Transformer, the Tanners Creek - Miami Fort Flowgate, the Graceton - Safe Harbor Line, and the 5004/5005 Interface.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in the first nine months of 2018. The number of congestion event hours in the Day-Ahead Energy Market was about six times the number of congestion event hours in the Real-Time Energy Market.

  But day-ahead congestion frequency decreased by 53.0 percent from 224,543 congestion event hours in the first nine months of 2017 to 105,437 congestion event hours in the first nine months of 2018 as a result of a significant decrease in up to congestion transaction (UTC) activities in response to the February 20, 2018, FERC order that limited UTC trading, effective February 22, 2018, to hubs, residual metered load, and interfaces.[140]

  Real-time congestion frequency increased by 2.7 percent from 16,473 congestion event hours in the first nine months of 2017 to 16,924 congestion event hours in the first nine months of 2018.
- **Congested Facilities.** Day-ahead, congestion event hours decreased on all types of facilities as a result of a significant decrease in UTC activities caused by the February 20, 2018 FERC order.

  The AEP - DOM Interface was the largest contributor to congestion costs in the first nine months of 2018. With $120.4 million in total congestion

140 162 FERC ¶ 61,139.

costs, it accounted for 10.8 percent of the total PJM congestion costs in the first nine months of 2018.

- **Zonal Congestion.** Using the constraint based measure, Dominion had the largest local congestion costs among all control zones in the first nine months of 2018. Dominion had $206.6 million in local congestion costs, comprised of $199.4 million in local day-ahead congestion costs and $7.2 million in local balancing congestion costs. The AEP - DOM Interface, the Cloverdale Transformer, the Graceton - Safe Harbor Line, the AP South Interface and the Person – Sedge Hill Line contributed $138.5 million, or 67.0 percent of the local Dominion control zone congestion costs. Using the less accurate area based measure, AEP had the largest local congestion costs among all control zones in the first nine months of 2018. AEP had $304.6 million in local congestion costs, comprised of $335.8 million in total day-ahead congestion costs and -$31.2 million in total balancing congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $255.9 million or 51.1 percent, from $501.0 million in the first nine months of 2017 to $757.0 million in the first nine months of 2018. The loss MWh in PJM increased by 823.7 GWh or 7.5 percent, from 11,036.7 GWh in the first nine months of 2017 to 11,860.3 GWh in the first nine months of 2018. The loss component of real-time LMP in the first nine months of 2018 was $0.02, compared to $0.01 in the first nine months of 2017.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first nine months of 2018 ranged from $49.5 million in February to $222.8 million in January.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $214.8 million or 38.0 percent, from $566.0 million in the first nine months of 2017 to $780.9 million in the first nine months of 2018.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs decreased by $41.1 million or 63.2 percent, from -$65.0 million in the first nine months of 2017 to -$23.9 million in the first nine months of 2018.
- **Total Marginal Loss Surplus.** The total marginal loss surplus increased in the first nine months of 2018 by $99.9 million or 63.9 percent, from $156.5 million in the first nine months of 2017, to $256.4 million in the first nine months of 2018.

Energy Cost

- **Total Energy Costs.** Total energy costs decreased by $154.7 million or 45.0 percent, from -$344.0 million in the first nine months of 2017 to -$498.7 million in the first nine months of 2018.
- **Day-Ahead Energy Costs.** Day-ahead energy costs decreased by $67.1 million or 13.8 percent, from -$484.4 million in the first nine months of 2017 to -$551.4 million in the first nine months of 2018.
- **Balancing Energy Costs.** Balancing energy costs decreased by $88.8 million or 65.4 percent, from $135.9 million in the first nine months of 2017 to $47.1 million in the first nine months of 2018.
- **Monthly Total Energy Costs.** Monthly total energy costs in the first nine months of 2018 ranged from -$150.9 million in January to -$33.6 million in February.

Section 11 Conclusion

Congestion is defined to be the total congestion payments by load in excess of the total congestion credits received by generation. The level and distribution of congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

Total congestion in the first nine months of 2018 increased significantly from the first nine months of 2017. The increase was a result of an increase in day-ahead congestion in January 2018 which was a result of high gas costs and associated LMPs in the early part of January 2018 and the use of high price oil fired units to control for contingencies caused by outages related to transmission upgrades in Virginia in May 2018.

Balancing explicit congestion increased by $3.1 million or 46.3 percent, from -$6.7 million in the first nine months of 2017 to -$3.6 million in the first nine months of 2018. The increase in balancing explicit costs was the result of an increase in balancing explicit congestion caused by up to congestion (UTCs) which went from -$7.0 million in the first nine months of 2017 to $6.3 million in the first nine months of 2018.

The monthly total congestion costs ranged from $45.2 million in February to $535.9 million in January, 2018. The balancing congestion costs were -$16.0 million and -$19.9 million in May and June. The large negative balancing congestion cost was caused in large part by UTCs profiting from day-ahead and real-time market modeling differences, including a number of constraints that were modeled in real-time market but not modeled in day-ahead market.

The impact of UTCs on the frequency of day-ahead congestion was illustrated by the significant reduction in day-ahead congestion event hours following the decrease in up to congestion (UTC) transaction activities that resulted from the February 20, 2018, FERC order that limited UTC trading to hubs, residual metered load, and interfaces.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 65.3, 90.3, 100.0, 50.0 and 87.6 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014/2015, 2015/2016, 2016/2017, 2017/2018 and the first four months of 2018/2019 planning periods.

Overview: Section 12, Planning

Generation Interconnection Planning

Existing Generation Mix

- As of September 30, 2018, PJM had an installed capacity of 195,488.2 MW. This measure differs from capacity market installed capacity because it includes energy only units, excludes all external units, and uses nameplate values for solar and wind resources. Of the 195,488.2 MW of installed capacity, 57,891.9 MW (29.6 percent) are coal fired steam units, 43,063.1 MW (22.0 percent) are combined cycle units and 34,257.6 MW (17.5 percent) are nuclear units.
- The largest zone by total installed capacity is AEP. Of the 195,488.2 MW of PJM installed capacity, 31,343.0 MW (16.0 percent) are in the AEP Zone, of which 14,727.8 MW (47.0 percent) are coal fired steam units, 6,990.0 MW (22.3 percent) are combined cycle units and 2,071.0 MW (6.6 percent) are nuclear units.
- The largest state by total installed capacity is Pennsylvania. Of the 195,488.2 MW of installed capacity, 43,207.6 MW (22.1 percent) are in Pennsylvania, of which 12,112.5 MW (28.0 percent) are combined cycle units, 9,648.8 MW (22.3 percent) are nuclear units and 9,467.7 MW (21.9 percent) are coal fired steam units.
- Of the 195,488.2 MW of installed capacity, 76,587.5 MW (39.2 percent) are from units older than 40 years, of which 41,426.7 MW (54.1 percent) are coal fired steam units and 16,044.9 MW (20.9 percent) are nuclear units.

Generation Retirements[141]

- There are 43,125.6 MW of generation that have been, or are planned to be, retired between 2011 and 2021, of which 30,821.4 MW (71.5 percent) are coal fired steam units. Coal unit retirements are primarily a result of the inability of coal units to compete with efficient combined cycle units burning low cost gas.

141 See PJM "Generator Deactivations," at <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.

- In the first nine months of 2018, 4,894.2 MW of generation retired. The largest generator that retired in first nine months of 2018 was the joint owned 600 MW Killen 2 unit (402 MW owned by AES Corporation and 198 MW owned by Vistra Energy Corporation) located in the Dayton Power and Light (DAY) Zone. Of the 4,894.2 MW of generation that retired, 2,364.0 MW (48.3 percent) were located in the DAY Zone.
- There are 12,468.0 MW of generation pending retirement after September 30, 2018, of which 6,791.0 MW (54.5 percent) are located in the ATSI Zone, 7,341.8 MW (58.9 percent) are coal fired steam units and 4,716.0 MW (37.8 percent) are nuclear units. The largest generator pending retirement is the 1,240 MW Perry U1 Nuclear Generating Unit located in the ATSI Zone.

Generation Queue[142]

- The total MW in queues increased by 22,169.1 MW (28.0 percent) from 79,224.3 MW at the end of 2017 to 101,393.4 MW on September 30, 2018.
- A significant shift in the distribution of unit types within the PJM footprint continues to develop as natural gas fired units enter the queue and coal fired steam units retire. As of September 30, 2018, there were 50,201.7 MW of natural gas fired capacity active, suspended or under construction in PJM queues (including combined cycle units, CTs, RICE units, and natural gas fired steam units). As of September 30, 2018, there were only 147.0 MW of coal fired steam capacity active, suspended or under construction in PJM queues.
- As of September 30, 2018, 3,969 projects, representing 504,007.2 MW, have entered the queue process since its inception in 1998. Of those, 805 projects, representing 59,737.9 MW, went into service. Of the projects that entered the queue process, 2,323 projects, representing 342,875.9 MW (68.0 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

142 See PJM "New Services Queue," at <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.

Regional Transmission Expansion Plan (RTEP)

Backbone Facilities

- There are currently three backbone projects under development, Surry Skiffes Creek 500kV, and the conversion of the Marion-Bayonne and Bayway-Linden lines from 138 kV to 345 kV.[143]

Market Efficiency Process

- Through September 30, 2018, PJM has completed two market efficiency cycles. In the first cycle, PJM received 93 proposals for 57 identified issues. In the second market efficiency cycle, PJM received 96 proposals for four identified issues. The proposal window for 2018/2019 will open on November 1, 2018, and will close on February 28, 2019.
- Approved market efficiency projects periodically undergo a reevaluation process to ensure that the benefit/cost ratio continues to meet the 1.25:1 threshold. The Transource AP-South project was reevaluated in September 2017, February 2018 and again in September 2018. The project exceeded the 1.25:1 threshold in all reevaluations.

PJM MISO Interregional Targeted Market Efficiency Process (TMEP)

- The first Targeted Market Efficiency Process (TMEP) analysis occurred in 2017 and included the investigation of congestion on 50 market to market flowgates. The study resulted in the evaluation of 13 potential upgrades, resulting in the recommendation of five TMEP projects. The five projects address $59 million in historical congestion, with a TMEP benefit of $99.6 million. The projects have a total cost of $20 million, with a 5.0 average benefit/cost ratio. PJM and MISO presented the five recommended projects to their boards in December, 2017, and both boards approved all five projects.[144]
- The 2018 TMEP analysis included the investigation of congestion on 61 market to market flowgates. The study resulted in the evaluation of

143 See "2017 RTEP Process Scope and Input Assumptions White Paper," P 25. <http://www.pjm.com/-/media/library/reports-notices/2017-rtep/20170731-rtep-input-assumptions-and-scope-whitepaper.ashx?la=en>.

144 See PJM. "*MISO PJM IPSAC*," (January 12, 2018) <http://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180112/20180112-ipsac-presentation.ashx>.

19 potential upgrades, resulting in the recommendation of two TMEP projects. The two projects address $25 million in historical congestion, with a TMEP benefit of $31.9 million. The projects have a total cost of $4.5 million, with a 7.1 average benefit/cost ratio. PJM and MISO will present the two recommended projects to their boards for approval in December, 2018.[145]

Supplemental Transmission Projects

- The average number of supplemental projects in each expected in service year increased by 500.0 percent, from 20 for years 1998 through 2007 (pre Order 890) to 120 for years 2008 through 2018 (post Order 890).

End of Life Transmission Projects

- An "End of life" transmission project is a project submitted for the purpose of replacing existing infrastructure that has, or is approaching, the end of its useful life. End of life transmission projects fall under the Transmission Owner Form 715 Planning Criteria, and are exempt from the competitive planning process.[146] End of life transmission projects are already included in the supplemental projects totals or, if included in the transmission owners' reliability plan, will be included in the baseline project list as a reliability criteria project.

Transmission Competition

- The MMU makes several recommendations related to the competitive transmission planning process. The recommendations include improved process transparency, incorporation of competition between transmission and generation alternatives and the removal of barriers to competition from merchant transmission. These recommendations will ensure that the process is an open and transparent process that results in the most cost effective solutions.
- On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM to develop a comparative framework to evaluate the quality and effectiveness of binding cost containment proposals versus proposals without cost containment provisions. The initial motion required the comparative framework to be presented at the December 2018 meeting of the MRC for vote and to be effective for the 2018 long lead project proposal window. At the August 23, 2018, meeting of the MRC, the committee approved a motion to delay the comparative framework deadlines by one year.

Board Authorized Transmission Upgrades

- The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals are periodically presented to the PJM Board of Managers for authorization. In the first nine months of 2018, the PJM Board approved $1.60 billion in upgrades.

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When the reportable transmission facilities need to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outage requests according to rules in PJM's Manual 3 to decide if the outage is on time or late and whether or not they will allow the outage.[147]
- There were 12,123 transmission outage requests submitted in the 2018/2019 planning period. Of the requested outages, 70.5 percent of the requested outages were planned for less than or equal to five days and 10.2 percent of requested outages were planned for greater than 30 days. Of the requested outages, 37.9 percent were late according to the rules in PJM's Manual 3.

145 See PJM. "*MISO PJM IPSAC*," (October 5, 2018) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20181005/20181005-ipsac-presentation.ashx>.
146 See PJM Operating Agreement. Schedule 6 § 1.5.8(o).
147 PJM. "Manual 03: Transmission Operations," Rev. 53 (June 1, 2018) Section 4.

Section 12 Recommendations

The MMU recommends improvements to the planning process:

Generation Retirements

- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[148] (Priority: Low. First reported 2013. Status: Not adopted.)

Generation Queue

- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service. (Priority: Medium. First reported 2014. Status: Partially adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

- The MMU recommends that PJM reevaluate the rules governing cost benefit analysis and cost allocation for economic projects. (Priority: Medium. New recommendation. Status: Not adopted.)

Supplemental Transmission Projects

- The MMU recommends, to ensure maximum competition, that PJM support ending the exemption of supplemental projects from the Order No. 1000 competitive process. (Priority: Medium. First reported 2017. Status: Not adopted.)

Transmission Competition

- The MMU recommends that PJM enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any

148 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000 <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf>.

barriers to entry and permit competition between incumbent transmission providers and merchant transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)

- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. (Priority: Low. First reported 2015. Status: Not adopted.)

Transmission Facility Outages

- The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the line. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)

Section 12 Conclusion

The goal of PJM market design should be to enhance competition and to ensure that competition is the driver for all the key elements of PJM markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on the energy and capacity markets. But when generating units retire or load increases, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in the affected area. In addition, despite FERC Order No. 1000, there is not yet a transparent, robust and clearly defined mechanism to permit competition to build transmission projects, to ensure that competitors provide a total project cost cap, or to obtain least cost financing through the capital markets.

The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and may effectively forestall the ability of generation to compete. But there is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly, whether there is more risk associated with the generation or transmission alternatives, or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

Managing the generation queues is a highly complex process. The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result. The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition for new generation investments are not created. Issues that need to be addressed include the ownership rights to CIRs, whether transmission owners should perform interconnection studies, and improvements in queue management to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress.

The PJM rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and merchant transmission providers. PJM should enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base. Because PJM now has the responsibility for planning the development of the grid under its RTEP process, property bought to facilitate future expansion should be a part of the RTEP process and be made available to all providers on equal terms.

There are currently no market incentives for transmission owners to submit and complete transmission outages in a timely and efficient manner. Requiring transmission owners to pay does not create an effective incentive when those payments are passed through to transmission customers. The process for the submission of planned transmission outages needs to be carefully reviewed and redesigned to limit the ability of transmission owners to submit transmission outages that are late for FTR auction bid submission dates and are late for the Day-Ahead Energy Market. The submission of late transmission outages can inappropriately affect market outcomes when market participants do not have the ability to modify market bids and offers.

Overview: Section 13, FTRs and ARRs

Auction Revenue Rights

Market Structure

- **Residual ARRs.** If ARR allocations are reduced as the result of a modeled transmission outage and the transmission outage ends during the relevant planning year, the result is that residual ARRs may be available. These residual ARRs are automatically assigned to eligible participants the month before the effective date. Residual ARRs are only available on paths prorated in Stage 1 of the annual ARR allocation, are only effective for single, whole months and cannot be self scheduled. Residual ARR clearing prices are based on monthly FTR auction clearing prices. Residual ARRs with negative target allocations are not allocated to participants. Instead they are removed and the model is rerun.

  In the first four months of the 2018/2019 planning period, PJM allocated a total of 24,920.9 MW of residual ARRs, up from 21,809.5 MW in the 2017/2018 planning period, with a total target allocation of $13.8 million for the first four months of the 2018/2019 planning period, up from $4.8 million for the 2017/2018 planning period.

- **ARR Reassignment for Retail Load Switching.** There were 16,177 MW of ARRs associated with $194,300 of revenue that were reassigned in the first four months of the 2018/2019 planning period. There were 44,823 MW of ARRs associated with $339,500 of revenue that were reassigned for the 2017/2018 planning period.

Market Performance

- **Revenue Adequacy.** For the first four months of the 2018/2019 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $243.1 million, while PJM collected $886.0 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. ARRs have historically been fully funded by the revenue collected from the Annual FTR Auction. As a result, ARRs do not receive revenue collected from the long term or monthly auctions. For the 2017/2018 planning period, the ARR target allocations were $573.8 million while PJM collected $601.2 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions.

- **ARRs as an Offset to Congestion.** ARRs did not serve as an effective way to return congestion revenues to load. Total ARR and self scheduled FTR revenue offset only 73.3 percent of total congestion costs, which include congestion in the Day-Ahead Energy Market and the balancing energy market, for the 2011/2012 planning period through the 2016/2017 planning period, under the previous allocation of balancing congestion. In the 2017/2018 planning period, in which balancing congestion and M2M payments were directly assigned to load, total ARR and self scheduled FTR revenues offset 50.7 percent of total congestion costs. Under the new rules for surplus congestion revenue allocation beginning in the 2018/2019 planning periods, ARRs, self scheduled FTRs and surplus congestion revenue would offset 95.9 percent of total congestion costs. The goal of the FTR market design should be to ensure that load has the rights to 100 percent of the congestion revenues.

Financial Transmission Rights

Market Structure

- **Supply.** In a given auction, market participants can sell FTRs that they have acquired in preceding auctions. In the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2018/2019 planning period, total participant FTR sell offers were 3,320,461 MW, up from 2,084,830 MW for the same period during the 2017/2018 planning period. GreenHat Energy's liquidated FTR positions are included in these FTR sell offers.
- **Demand.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2018/2019 planning period increased 9.5 percent from 8,621,736 MW for the same time period of the prior planning period, to 9,443,085 MW.
- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 76.2 percent of prevailing flow and 82.9 percent of counter flow FTRs for January through September of 2018. Financial entities owned 70.3 percent of all prevailing and counter flow FTRs, including 63.2 percent of all prevailing flow FTRs and 81.1 percent of all counter flow FTRs during the period from January through September, 2018.

Market Behavior

- **FTR Forfeitures.** For the period of January 19, 2017, through September 30, 2018, total FTR forfeitures were $12.5 million.
- **Credit.** There were 13 collateral defaults in the first nine months of 2018, not involving GreenHat Energy, LLC, for a total of $640,670. Most collateral defaults were cured promptly. There were 36 payment defaults in the first nine months of 2018, not involving GreenHat Energy, LLC for a total of $86,666, which resulted in the default of Amerigreen Energy, Inc. on June 12, 2018.[149]

  On June 21, 2018, GreenHat Energy, LLC was declared in default for two collateral calls totaling $2.8 million and two payment defaults totaling $3.9 million.[150] GreenHat held a large FTR position which, according to current tariff provisions, must be liquidated in the FTR auctions closest to the effective dates of the positions held.[151] The net gain or loss on these liquidated positions will be added to the payment default amount that will then be allocated to PJM members according to OA sections 15.1.2A(1) and 15.2.2. On July 26, 2018, PJM filed a waiver request at FERC asking that PJM only be required to liquidate FTRs for the prompt months to allow Member discussion on how to proceed with GreenHat's large FTR portfolio.[152] Members selected to settle GreenHat's FTR portfolio at the time the FTRs are due, so default allocation assessment charges will continue to accrue through May 2021.

149 Daugherty, Suzanne, email sent to the MC, MRC, CS and MSS email distribution list, "PJM Member Default – Amerigreen Energy, Inc.," (June 13, 2018).
150 Daugherty, Suzanne, Email sent to the MC, MRC, CS, and MSS email distribution list, "Notification of GreenHat Energy, LLC Payment Default," (June 22, 2018).
151 "PJM Manual 6: Financial Transmission Rights," Rev. 20 (June 1, 2018) at 47.
152 See "Request of PJM Interconnection, LLC for a waiver effective July 27, 2018," Docket No. ER18-2068 (July 26, 2018).

Market Performance

- **Volume.** In the first four months of the 2018/2019 planning period Monthly Balance of Planning Period FTR Auctions cleared 1,186,470 MW (12.6 percent) of FTR buy bids and 751,979 MW (22.6 percent) of FTR sell offers.
- **Price.** The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2018/2019 planning period was $0.13, up from $0.10 per MW for the same period in the 2017/2018 planning period.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated $33.5 million in net revenue for all FTRs for the first four months of the 2018/2019 planning period, up from $16.2 million for the same time period in the 2017/2018 planning period.
- **Revenue Adequacy.** FTRs were paid at 100 percent of the target allocation level for the first four months of the 2018/2019 planning period. This high level of revenue adequacy was at least partially a result of FERC redefining the FTR congestion calculation to exclude balancing congestion and M2M payments.
- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. In the first four months of the 2018/2019 planning period, physical entities made $19.4 million in profits, while receiving $46.9 million in returned congestion from self scheduled FTRs, and financial entities made $48.9 million in profits.

Section 13 Recommendations

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if the Long Term FTR product is not eliminated, Long Term FTR Market be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that the full capability of the transmission system be allocated as ARRs prior to sale as FTRs. Reductions for outages and increased system capability should be reserved for ARRs rather than sold in the Long Term FTR Auction. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used to buy counter flow FTRs for the purpose of improving FTR payout ratios.[153] (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for allocating ARRs. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR market participants. (Priority: High. First reported 2012. Status: Not adopted. Rejected by FERC.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR

153 See "PJM Manual 6: Financial Transmission Rights," Rev. 20 (June. 1, 2018) at 55.

forfeiture rule to increment offers and decrement bids. (Priority: High. First reported 2013. Status: Adopted 2017)

- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs including clear rules for what defines persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- The MMU recommends that PJM report correct monthly payout ratios to reduce understatement of payout ratios on a monthly basis. (Priority: Low. First reported 2012. Status: Adopted 2016.)
- The MMU recommends that PJM continue to review the FTR liquidation process. (Priority: High. First reported Q2, 2018. Status: Not adopted.)

Section 13 Conclusion

The annual ARR allocation should be designed to ensure that the rights to all congestion revenues are assigned to firm transmission service customers, without requiring contract path physical transmission rights that are impossible to define and enforce in LMP markets. The fixed charges paid for firm transmission services result in the transmission system, which provides physically firm transmission service, which results in the delivery of low cost generation, which results in load paying congestion revenues, in an LMP market.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives the rights to all the congestion revenues and has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 63.8, 86.5, 98.1, 50.6 and, if surplus through September 2018 were distributed, 95.9 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014/2015, 2015/2016, 2016/2017, 2017/2018 and the first four months of 2018/2019 planning periods.

In the 2014/2015, 2015/2016 and 2016/2017 planning periods, PJM significantly reduced the allocation of ARR capacity, and FTRs, in order to guarantee full FTR funding. PJM reduced system capability in the FTR auction model by including more outages, reducing line limits and including additional constraints. PJM's modeling changes resulted in significant reductions in Stage 1B and Stage 2 ARR allocations, a corresponding reduction in the available quantity of FTRs, a reduction in congestion revenues assigned to ARRs, and an associated surplus of congestion revenue relative to FTR target allocations. This also resulted in a significant redistribution of ARRs among ARR holders based on differences in allocations between Stage 1A and Stage 1B ARRs. Starting in the 2017/2018 planning period, with the allocation of balancing congestion and M2M payments to load rather than FTRs, PJM increased system capability allocated to Stage 1B and Stage 2 ARRs, but continued to conservatively select outages to manage FTR funding levels.

Load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested repeatedly.[154] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[155] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. As of the 2017/2018 planning period, as a result of the FERC order, balancing congestion and M2M payments are assigned to load, rather than to FTR holders. The Commission's order shifts substantial revenue from load to the holders of FTRs and reduces the ability of load to offset congestion. This approach ignores the fact that loads must pay both day-ahead and balancing congestion, and that congestion is defined, in an accounting sense, to equal the sum of day-ahead and balancing congestion. Eliminating balancing congestion from the FTR revenue calculation requires load to pay twice for congestion. Load will pay for the physical transmission system, will pay in

154 See FERC Dockets Nos. EL13-47-000 and EL12-19-000.
155 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 156 FERC ¶ 61,093 (2017).

excess of generator revenues and will pay negative balancing congestion again. The result will be that load will get back less than total congestion.

These changes were made in order to increase the payout to holders of FTRs who are not loads. In other words, load will continue to be the source of all the funding for FTRs, while payments to FTR holders who did not receive ARRs exceed total congestion on their FTR paths and result in profits to FTR holders.

Load was made significantly worse off as a result of the changes made to the FTR/ARR process by PJM based on the FERC order of September 15, 2016. ARR revenues were significantly reduced for the 2017/2018 FTR Auction, the first auction under the new rules. ARRs and self scheduled FTRs offset 50.7 percent of total congestion costs for the 2017/2018 planning period rather than the 55.6 percent offset that would have occurred under the prior rules, a difference of $124.9 million. There was a significant amount of congestion in January 2018 which adversely affected the congestion offset value of ARRs. ARR revenue is fixed at annual auction prices, but congestion revenue varies with congestion. The net increase in ARR value from the reassignment of balancing congestion and M2M payments to load, as predicted by proponents of the reassignment, did not occur.

If these allocation rules had been in place beginning with the 2011/2012 planning period, ARR holders would have received a total of $1,159.1 million less in congestion offsets from the 2011/2012 through the 2017/2018 planning period. The total overpayment to FTR holders for the 2011/2012 through 2017/2018 planning period would have been $1,315.1 million. The underpayment to load and the overpayment to FTR holders is a result of several factors in the rules, all of which mean the transfer of revenues to FTR holders and the shifting of costs to load. Load is now required to pay for balancing congestion, which significantly increases costs to load and significantly increases revenues paid to FTR holders while degrading the ability of ARRs to provide a predictable offset to congestion costs. PJM will continue to clear counter flow FTRs using auction revenues greater than the ARR target allocations in order to make it possible to sell more prevailing flow FTRs. FTR holders will also receive day-ahead congestion revenues in excess of target allocations. FTR holders will also receive additional auction revenue, which is what FTR holders were willing to pay for FTRs above what is provided to ARR holders through ARR target allocations on defined paths.

Beginning with the 2018/2019 planning period, surplus auction revenue, which is defined as day-ahead congestion revenue and surplus auction revenue remaining after funding ARRs, and then FTRs, will be allocated to ARRs pro-rata based on ARR target allocations.[156] This surplus revenue is generated by a failure of the current ARR/FTR construct to make all congestion revenue rights available to load in the form of ARRs. All congestion revenue belongs to ARR holders, and PJM's new surplus congestion allocation rule is an attempt to get closer to that goal. However, under the current rules, ARR holders will only have access to this surplus after full funding of FTRs is accomplished, which does not fully recognize ARR holders' primary rights to this surplus congestion revenue. If this rule had been in effect for the 2017/2018 planning period, ARRs and FTRs would have offset 76.8 percent of total congestion rather than 50.7 percent. For the first four months of the 2018/2019 planning period, if the surplus auction revenue were distributed to load, load would have offset 95.9 percent of congestion costs. Under the previous rule, which did not include the allocation of this surplus to load, load would have offset only 84.7 percent of their congestion costs.

Revenue adequacy has received a lot of attention in the PJM FTR Market. There are several factors that can affect the reporting, distribution of and quantity of funding in the FTR Market. Revenue adequacy is misunderstood. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy even when defined correctly. Load does have those rights based on load's payment for the transmission system and load's payment of total congestion.

Clearing prices fell and cleared quantities increased from the 2010/2011 planning period through the 2013/2014 planning period. The market response to lower revenue adequacy was to reduce bid prices and to increase bid

156 163 FERC ¶61,165 (2018).

volumes and offer volumes. In the 2014/2015, 2015/2016 and 2016/2017 planning periods, due to reduced ARR allocations resulting from PJM's actions to manage FTR revenue, FTR volume decreased relative to the 2013/2014 planning period. The reduction in ARR allocations and resulting FTR volume caused, by definition, an improvement in revenue adequacy, and also resulted in an increase in the prices of FTRs. Increased FTR prices resulted in increased ARR target allocations, because ARR target allocations are based on the Annual FTR Auction nodal prices. Beginning in the 2017/2018 planning period, based on the reallocation of balancing congestion and M2M payments to load, PJM reduced outages in the Annual FTR Auction model. This increased FTR capability, but ARR target allocations decreased due to lower FTR clearing prices.

Within a portfolio, FTR positive and negative target allocations are currently netted prior to the application of the payout ratio and end of planning period uplift calculation to the positive target allocation FTRs. The current method requires those participants with fewer negative target allocation FTRs to subsidize those with more negative target allocation FTRs and treats a positive target allocation FTR differently depending on the portfolio of which it is a part. The correct method would treat all FTRs with positive target allocations exactly the same, which would eliminate this form of cross subsidy. The net of a participant's portfolio should not determine their FTR uplift liability, rather their portion of total positive target allocations should be used to determine a participant's uplift charge. The FTR Market cannot work efficiently if FTR buyers do not receive payments consistent with the performance of their FTRs. Eliminating the portfolio subsidy would be a good first step in that direction.

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. Counter flow FTR holders make payments over the planning period, in the form of negative target allocations. These negative target allocations are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent. There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the impact of lower payouts among counter flow FTR holders and prevailing flow FTR holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations. The FTR Market cannot work efficiently if FTR buyers do not receive payments consistent with the performance of their FTRs. Eliminating the counter flow subsidy would be another good step in that direction. The MMU recommends that counter flow and prevailing flow FTRs be treated symmetrically with respect to the application of a payout ratio.

The overallocation of Stage 1A ARRs results in FTR overallocations on the same facilities. While Stage 1A overallocation has been reduced, Stage 1A ARR overallocation is a source of reduced revenue and cross subsidy.

The MMU recommends that the basis for the Stage 1A assignments be reviewed and made explicit and that the role of out of date generation to load paths be reviewed beyond the replacement of retired generation that was implemented. There is a reason that transmission is not built to address the Stage 1A overallocation issue. PJM's transmission planning process (RTEP) does not identify a need for new transmission because many of the over allocations are due to outages in the FTR model, or are flowgates, not actual system limitations. Capacity issues do not persist if the modeled outages are removed, so there is no need to expand the transmission system to support them. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load paths to assign Stage 1A rights that have nothing to do with actual power flows.

In addition to addressing these issues, the approach to the question of FTR funding should also examine the fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion. The MMU recommends that the transmission modeling in the FTR auction and persistent FTR path overallocation issues be reviewed and modifications implemented. Regardless of how these issues are addressed, funding issues that persist as a result of modeling differences and flaws in the design of the FTR Market should be borne by FTR holders operating in the voluntary FTR Market and not imposed on load through the mechanism of balancing congestion.

It has become increasingly clear that the Long Term FTR Auction structure should be significantly modified. It is not clear, in a competitive market, why participation in the Long Term FTR Auction continues to be very low for the second and third year long term product. In a competitive market the price of Long Term FTRs would be expected to converge with the prices of Annual FTRs, but there has been a persistent, wide divergence that has made the purchase of Long Term FTRs persistently very profitable. Recent changes to improve the modeling of the next year's auction model and include an offline ARR allocation model are steps in the right direction, but do not do enough to guarantee ARR holders' rights to the congestion being auctioned in the Long Term FTR Auction.

The MMU recommends that the Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the MMU recommends that Long Term FTR Market be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. This would ensure ARR holders' rights to congestion while maintaining the ability for participants to purchase congestion offsets for future planning periods.